Indiana Electricity Projections:
The 2019 Forecast

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Foreword

This report presents the 2019 projections of future electricity requirements for the state of Indiana for the period 2018-2037. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the seventeenth set of projections.

The objective of SUFG, as defined in Indiana Code 8-1-8.5 (amended in 1985), is as follows:

To arrive at estimates of the probable future growth of the use of electricity... *"the commission shall establish a permanent forecasting group to be located at a state supported college or university within Indiana. The commission shall financially support the group, which shall consist of a director and such staff as mutually agreed upon by the commission and the college or university, from funds appropriated by the commission. This group shall develop and keep current a methodology for forecasting the probable future growth of the use of electricity within Indiana and within this region of the nation. To do this the group shall solicit the input of residential, commercial and industrial consumers and the electric industry."*

This report provides projections from a statewide perspective. Individual utilities will experience different levels of growth due to a variety of economic, geographic, and demographic factors.

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. With the exception of the upgrades described in Chapter 2, details on the operation of the modeling system are limited; for more detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

http://www.purdue.edu/discoverypark/SUFG/

The authors would like to thank the Indiana utilities, consumer groups and industry experts who contributed their valuable time, information and comments to this forecast. Also, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its support, input and suggestions.

This report was prepared by the State Utility Forecasting Group. The information contained in this forecast should not be construed as advocating or reflecting any other organization's views or policy position. Further details regarding the forecast and methodology may be obtained from SUFG at:

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Chapter 1

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its eighteenth set of projections of future electricity usage, peak demand, prices and resource requirements. The projections in this forecast are lower than those in the 2017 forecast and 2018 forecast update, primarily due to increases in energy efficiency and less optimistic economic projections, compared to the earlier projections.

This forecast projects electricity usage to grow at a rate of 0.67 percent per year over the 20 years of the forecast. Peak electricity demand is projected to grow at an average rate of 0.60 percent annually. This corresponds to about 125 megawatts (MW) of increased peak demand per year. The growth in the second half of the forecast period (2028-2037) is stronger than the growth in the first ten years.

The 2019 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2026 and then slowly decrease afterwards. A number of factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production.

This forecast indicates that the state does not need significant additional resources until 2024. This forecast indicates a need for a mix of natural gas-fired combustion turbines and combined cycle units, with wind and solar capacity. Wind capacity is added in the first half of the forecast, solar is added later and natural-gas units are added throughout the forecast. In the long term, the projected additional resource requirements are higher than in previous forecasts. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report.

While SUFG identifies resource needs in its forecasts and reports those needs according to generating unit types, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electric energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial and industrial.

Chapter 2 of the report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts.

Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price, while Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections for each major consumption sector in the state under three scenarios.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

Finally, an Appendix depicts the data sources used to produce the forecast and provides historical and forecast data for energy, peak demand and prices.

The Regulated Modeling System

The SUFG modeling system explicitly links electricity costs, prices and sales on a utility-by-utility basis under each scenario. Econometric and end-use models are used to project electricity use for each major customer group — residential, commercial and industrial — using fuel prices and economic drivers to simulate growth in electric energy use. The projections for each utility are developed from a consistent set of statewide economic, demographic and fossil fuel price projections. In order to project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. These resource plans reflect "need" from both a statewide and utility perspective.

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin.[1] Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. In 2009 SUFG began using reserve margins that reflect the planning reserve requirements of the utilities' regional transmission organizations to determine the reserve requirements for the forecasts. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 19.1 percent. This represents a slightly higher reserve margin than the 18.9 percent figure used in the 2018 forecast. The increase in the statewide reserve requirements results from changes in reserve requirements at the regional transmission organizations.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables.[2] These assumptions are summarized below.

Economic Activity Projections

One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2019 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.83 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.72 percent.

Other key economic projections from CEMR are:

- Real personal income (a residential sector model driver) is expected to grow at a 1.73 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.95 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 2.01 percent real annual rate.

To capture some of the uncertainty in energy forecasting, SUFG also requested CEMR to produce low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection.

Demographic Projections

The projection for population growth in Indiana is 0.36 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.09 percent over the forecast period.

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[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 19.1 percent reserve margin is equivalent to a 16.0 percent capacity margin.
Capacity Margin = [(Capacity-Peak Demand)/Capacity]
Reserve Margin = [(Capacity-Peak Demand)/Peak Demand]

[2] Exogenous variables are those variables that are determined outside the modeling system and are then used as inputs to the system.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the January 2019 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price[3] projections are as follows:

Natural Gas Prices: Natural gas prices decreased significantly from 2008 to 2012. Prices then rebounded slightly in 2013 and 2014 before another dip in 2015 and 2016. Natural gas price is projected to increase gradually for the remainder of the forecast horizon.

Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatt-hours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 0.67 percent, while the growth rate for peak demand is 0.60 percent. The growth rates in the 2018 forecast update for electricity requirements and peak demand were 0.88 and 0.83 percent, respectively. The 2019 forecast grows more slowly than the previous ones, primarily due to less optimistic economic projections.

Lower growth is seen in all three sectors (residential, commercial and industrial), as shown in Table 1-1. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also lower than in the previous forecasts. The projections of peak demand are for normal weather patterns. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 1-2, the annual increase is about 125 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2018 and 2017 Projections)

Sector	Current (2018-2037)	2018 (2016-2035)	2017 (2016-2035)
Residential	0.45	0.54	0.48
Commercial	-0.10	0.38	0.36
Industrial	1.26	1.45	2.04
Total	0.67	0.88	1.12

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency is netted from the demand projection and supply-side resources are added as necessary to maintain a 19.1 percent reserve margin. Demand response[4] loads are treated as an existing resource that can be called on to meet the peak load.

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental energy efficiency programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 180 MW at the beginning of the forecast period and by about 800 MW at the end of the forecast. Energy efficiency projections were estimated from utility integrated resource plan filings and from information collected directly from the utilities by SUFG.

These energy efficiency projections do not include the demand response loads, which are projected to remain around 1,600 MW over the forecast horizon. See Chapter 4 for additional information about utility-sponsored energy efficiency and demand response.

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[3] Real prices are calculated to reflect the change in the price of a commodity after taking out the change in the general price levels (i.e., the inflation in the economy).

[4] Demand response includes loads that can be interrupted by the utility during times of high system demand, generation shortages, or high wholesale market prices. They include direct load control and loads under industrial interruptible rates.

Figure 1-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)

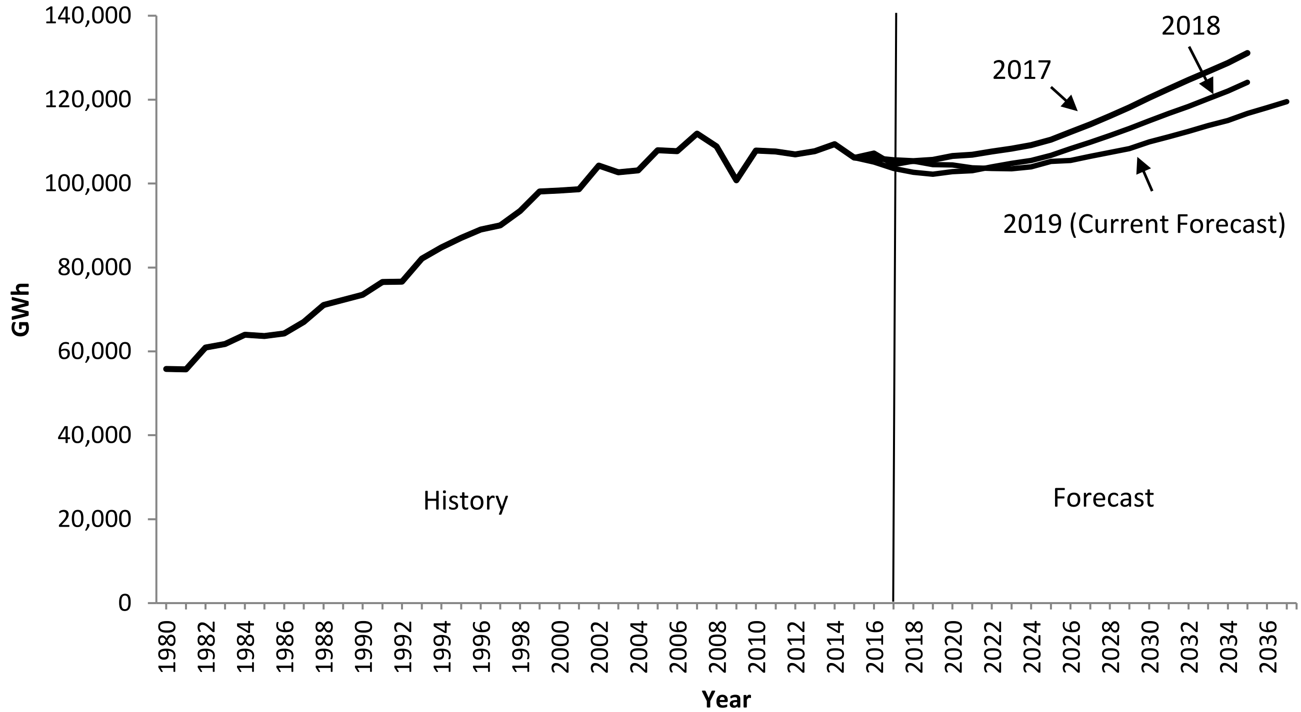
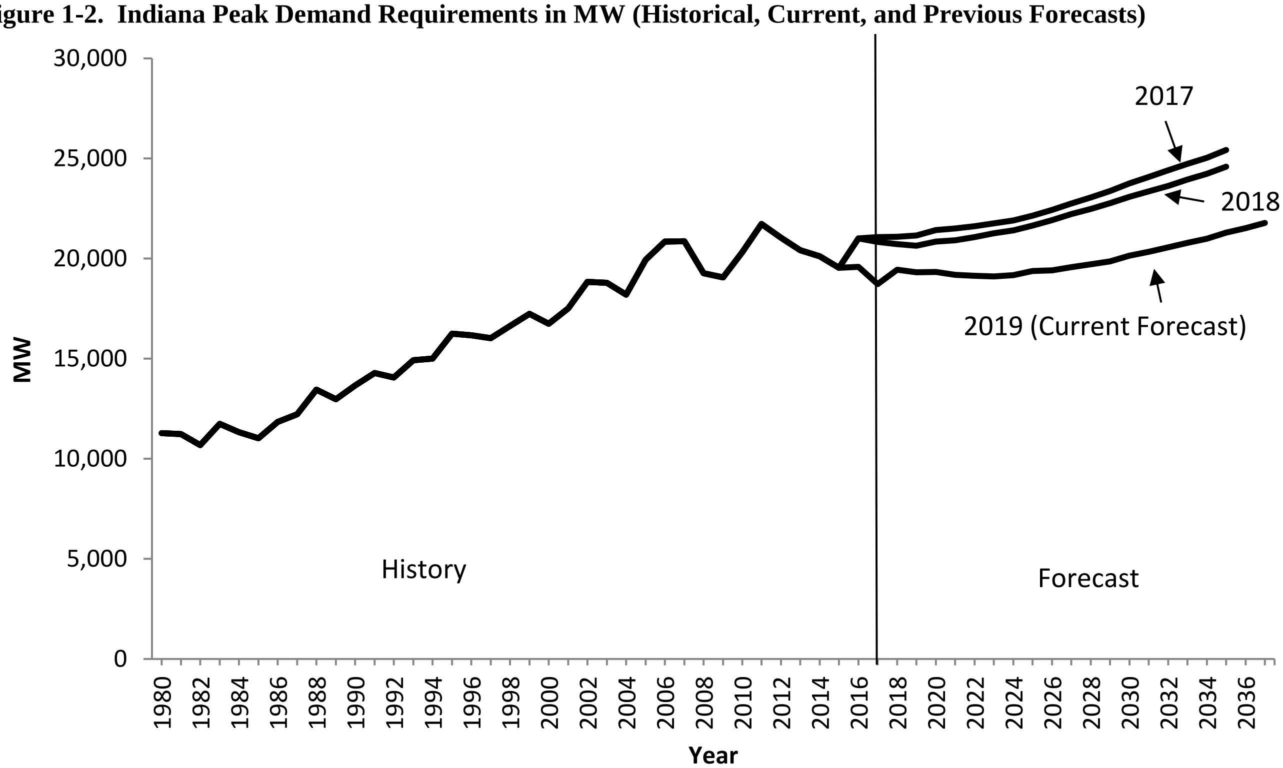


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generation resources are then added as necessary during the forecast period to maintain a statewide 19.1 percent reserve margin. The resource type is selected to minimize the overall cost of meeting the load.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. This forecast indicates that the state does not need additional resources until 2024. Since there is little growth in peak demand through the first half of the forecast, new resource needs are driven largely by retirements of existing capacity. Resource needs in the last ten years of the forecast are driven by a combination of increasing demand and additional unit retirements. Despite the lower peak demand projection, the projected additional resource requirements are higher than in previous forecasts in the long term. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report.

In addition to the amount of resources needed to meet the target reserve margin, Table 3-4 shows the resources selected by the optimization model to meet future electricity demand at least cost. This model selects a mix of natural gas-fired combustion turbines and combined cycle units, with wind and solar capacity. Wind capacity is added in the first half of the forecast, solar is added later and natural-gas units are added throughout the forecast.

Figure 1-3. Indiana Total Demand and Supply in MW (SUFG Base)

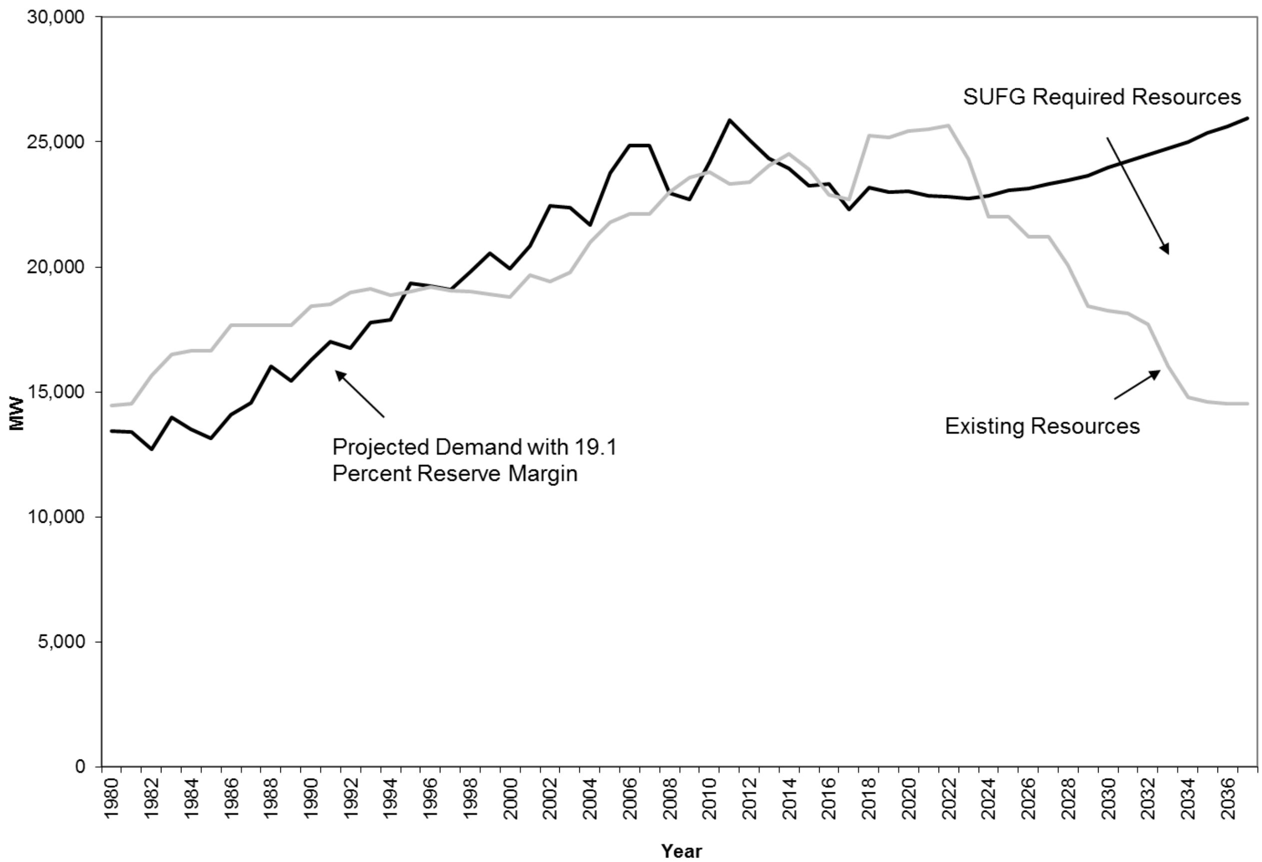


Table 1-2. Indiana Resource Plan in MW (SUFG Base)

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]					Reserve Margin[6] (percent)
					CT	CC	Wind	Solar	Total	
2018	19,444	25,271		0	0	0	0	0	0	30
2019	19,314	25,175	-96	0	0	0	0	0	0	30
2020	19,326	25,429	254	0	0	0	0	0	0	32
2021	19,184	25,500	71	0	0	0	0	0	0	33
2022	19,138	25,645	145	0	0	0	0	0	0	34
2023	19,105	24,315	-1,329	0	0	23	0	0	23	27
2024	19,169	22,014	-2,301	818	211	1,081	0	0	1,292	22
2025	19,376	22,015	1	1,063	578	1,566	1,000	0	3,144	25
2026	19,417	21,189	-826	1,938	584	2,164	2,000	0	4,748	24
2027	19,572	21,190	0	2,123	922	2,330	2,323	0	5,575	26
2028	19,711	20,065	-1,124	3,413	1,172	2,344	2,323	0	5,839	21
2029	19,862	18,442	-1,623	5,215	2,130	2,853	2,323	0	7,306	19
2030	20,139	18,243	-199	5,745	2,265	3,248	2,323	0	7,836	19
2031	20,346	18,131	-112	6,103	2,265	3,605	2,323	0	8,193	19
2032	20,562	17,719	-412	6,772	2,637	3,902	2,323	0	8,862	19
2033	20,787	16,009	-1,710	8,750	3,009	5,509	2,323	0	10,841	19
2034	20,997	14,799	-1,210	10,211	3,425	6,554	2,323	0	12,301	19
2035	21,296	14,589	-210	10,777	3,425	6,595	2,323	750	13,092	19
2036	21,521	14,539	-50	11,095	3,425	6,681	2,323	1,081	13,510	19
2037	21,781	14,514	-25	11,430	3,425	6,837	2,323	1,337	13,921	19

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.
6 The reserve margin reflects existing and approved resources plus additional selected resources, after adjusting for the expected availability of intermittent resources at the time of peak demand.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2017. Therefore, 2018 and 2019 numbers represent projections.

Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase by 35 percent from 2017 to 2026 and then slowly decrease by 8 percent until the end of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2017" is the base case projection contained in SUFG's 2017 forecast and the one labeled "2018" is the base case projection from SUFG's 2018 forecast update. For the prior price forecasts, SUFG rescaled the original price projections to 2017 dollars (from 2015 dollars) using the personal consumption deflator from the CEMR macroeconomic projections.

A number of factors determine the differences among the price projections in Figure 1-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 0.67, 0.39, and 1.02, respectively. These differences are due to economic growth assumptions in the scenario-based projections. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2017 Dollars) (Historical, Current, and Previous Forecasts)

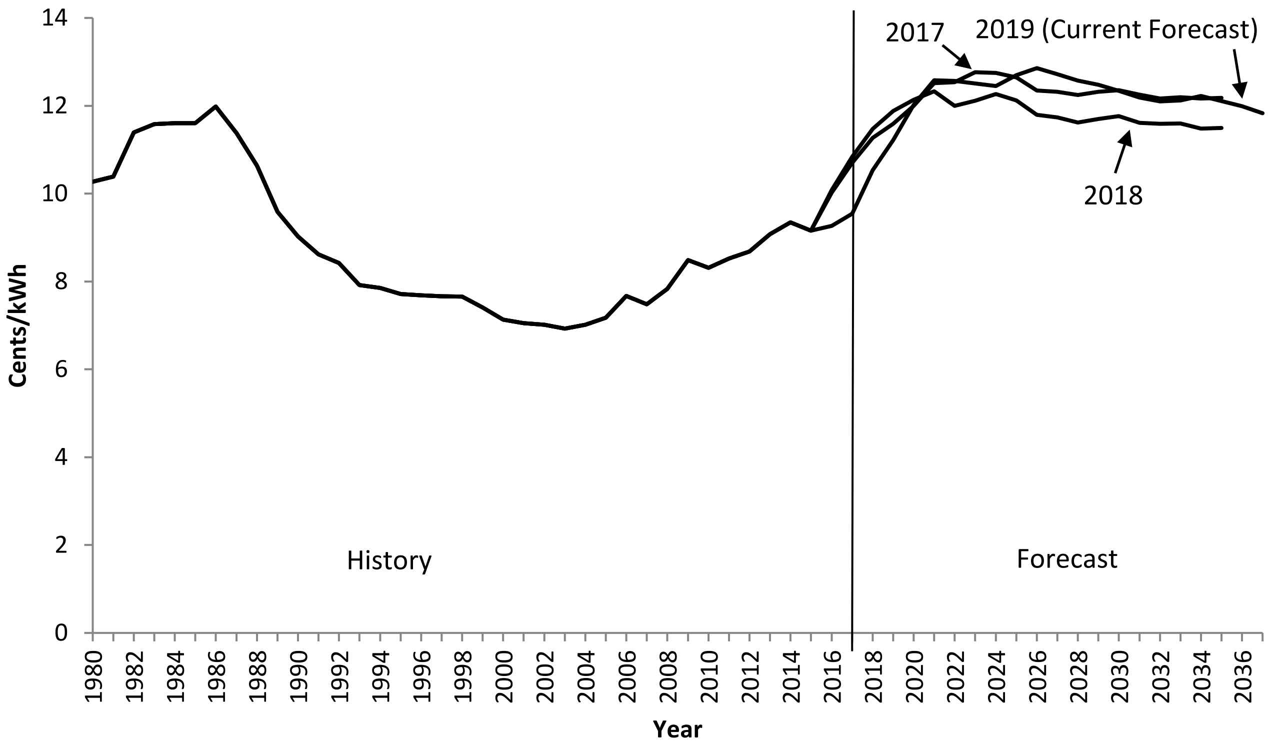
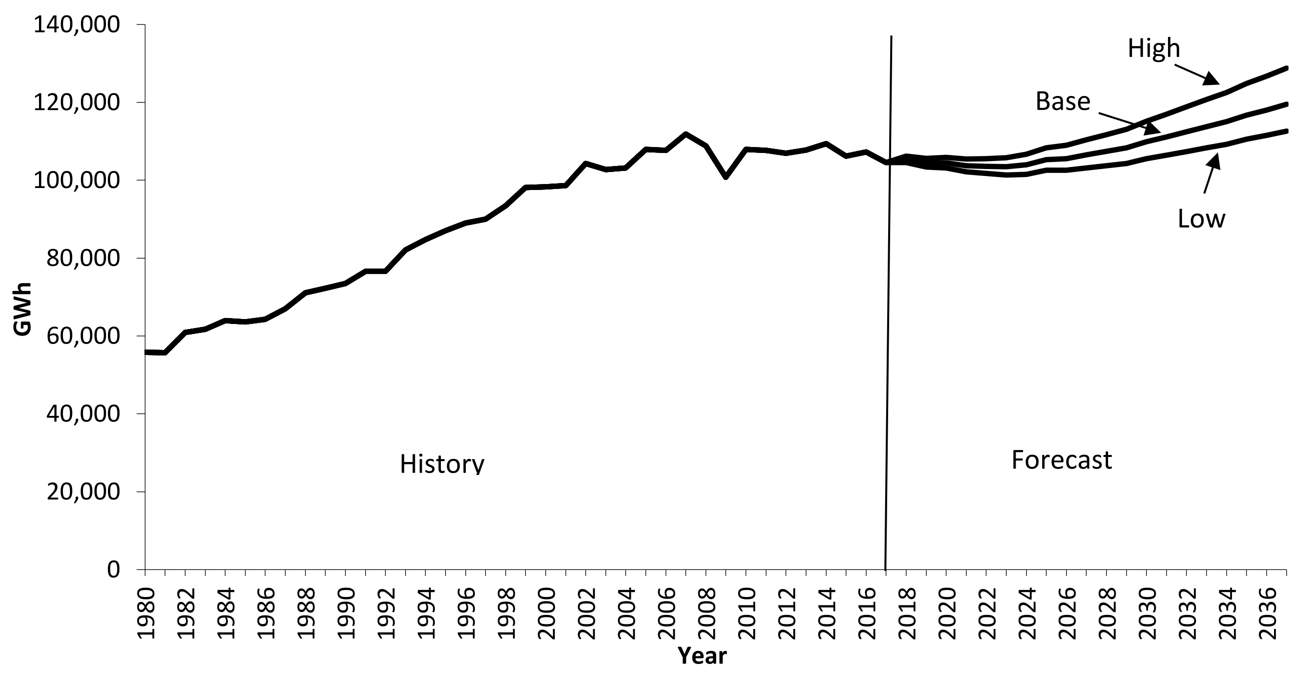


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



Chapter 2

Overview of the SUFG Electricity Modeling System

Modeling System Changes

Starting in 2016, SUFG performed a significant upgrade to its integrated electricity modeling system, which is used to project electricity demand, supply and price for each electric utility in the state under Indiana's present regulatory structure. The most significant change is replacing the electric utility simulation model, the Load Management Strategy Testing Model (LMSTM), with Aurora.

Due to the manner in which Aurora models demand response (DR) loads, there has been a definitional change in what SUFG reports as peak demand. Previously, the unadjusted peak demands produced by the forecasting models were reduced by the amount of available DR to determine the net peak demand. Because Aurora treats DR as a resource in determining the system economic dispatch and future resource needs, the peak demand projections provided in this report have not been adjusted for DR. DR is now reflected in the existing resource numbers.

Regulated Modeling System

The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various models until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics.

A distinctive characteristic of the modeling system is its ability to capture the interaction between future electricity demand and electricity prices through an iterative process. During each cycle of the process, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the utility finance & rates model to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the models until equilibrium is attained as is illustrated in Figure 2-1.

Figure 2-1. Cost-Price-Demand Feedback Loop

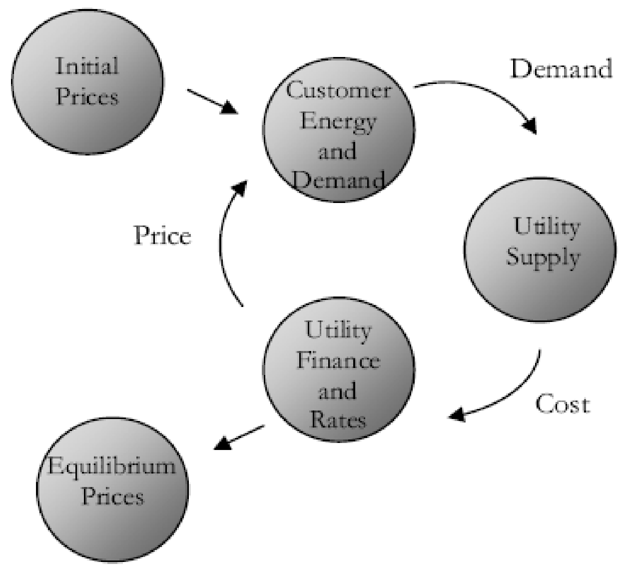
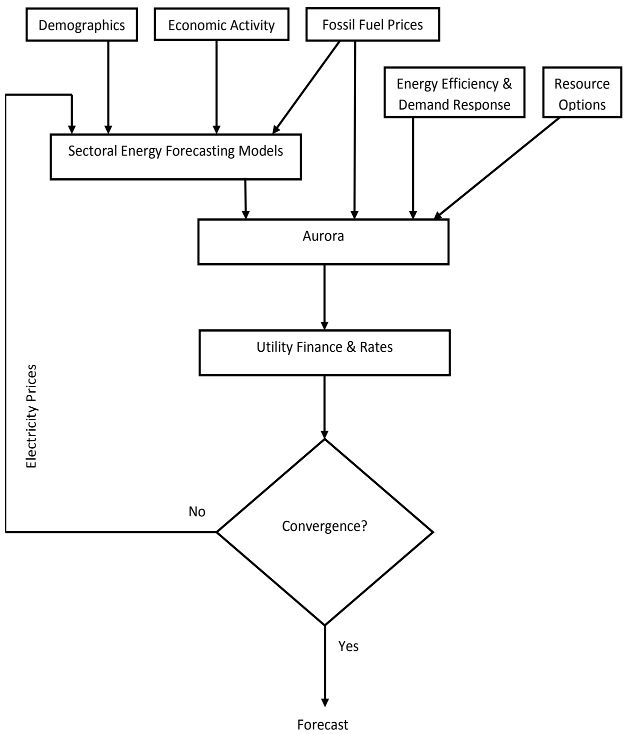


Figure 2-2 is a flowchart that illustrates how the modeling system functions. Projections of demographic, economic, and price drivers are inputs to utility and customer sector specific forecasting models. The energy and peak demand forecasts are inputs to Aurora, which simulates economic dispatch, trade among the utilities, and determines future resources. Cost information from Aurora are passed to the utility finance models to determine the resulting prices. The energy forecasting models are then rerun with the new prices, starting the next iteration. The process is repeated until prices from one iteration to the next are stable, indicating that convergence has been achieved.

Figure 2-2. Forecasting Modeling System Flowchart



Energy Forecasting Models

The energy forecasting models are used to develop projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Vectren Energy Delivery of Indiana - South. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association.

Utility-specific projections of sectoral energy use and prices are developed for each of the three scenarios. These projections are based on projections of demographics, economic activity and fossil fuel prices that are developed outside the modeling system. They are also based on projections of electricity prices for the utilities that are developed within the framework of the modeling system.

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

Aurora

Energy Exemplar's Aurora is an optimization program that can perform economic dispatch of generators, allowing for trade among utilities, and determine least-cost resource expansion. Within the SUFG integrated modeling system, it is used to determine the operating costs associated with meeting future loads and the costs of expanding the future set of resources necessary to meet future reserve requirements.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, natural gas-fired combustion turbines and combined cycle units, nuclear, and pulverized coal. Costs and operating characteristics were taken from the Energy Information Administration (EIA). Due to time and data limitations, demand-side resources were not modeled as a resource option. Utility energy efficiency programs and DR were modeled as fixed quantities based on utility-provided information. See Chapter 4 for more information on the modeling of demand-side resources.

The most recent version of Aurora has the functionality to allow for construction of partial resources. Thus, the model may select to add a fraction of a unit rather than being limited to full units. SUFG has elected to use this option since it facilitates finding an equilibrium solution. Also, while SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Utility Finance & Rates Models

As part of the upgrades to the modeling system, SUFG has incorporated new financial models to project future electric rates. Previously, the finance and rates submodels of LMSTM performed this function. The current financial model is a modified version of the ORFIN model that was developed by Oak Ridge National Lab. The models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts.

Resource Requirements

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin. Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. More recently, the regional transmission organizations (RTOs) that encompass Indiana utilities have determined planning reserve requirements for their members. Starting with the 2009 forecast, SUFG has used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity[1] among the utilities provides a statewide reserve requirement of approximately 19.1 percent. It should be noted that the change from a 15 percent to a 19.1 percent target in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the RTOs. Rather, it represents a change by SUFG to a target that is based on the more rigorous analyses of the RTOs as compared to the previous rule of thumb method.

Previously, SUFG developed its own method for determining the type of resources (such as peaking or baseload) and for assigning the need for resources to individual utilities. This method was considered to be "reasonable" but not optimal. Now the decisions of what types of resources to add and where are left to Aurora. This results in the lowest cost options for meeting future loads to be selected and removes the need for analyst judgment. Demand response loads are also modeled within Aurora, so they are no longer accounted for using an after-the-fact adjustment.

As before, the existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC).

Scenarios

SUFG's electricity projections are based on assumptions such as economic growth, construction costs and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another major source of uncertainty is the statistical error inherent in the structure of any forecasting model. To provide an indication of the importance of these sources of uncertainty, scenario-based projections are developed by operating the modeling system under varying sets of assumptions. These low probability, low and high growth scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

Presentation and Interpretation of Forecast Results

There are several methods for presenting the various projections associated with the forecast. The actual projected value for each individual year can be provided or a graph of the trajectory of those values over time can be used. Additionally, average compound growth rates can be provided. There are advantages and disadvantages associated with each method. For instance, while the actual values provide a great deal of detail, it can be difficult to visualize how rapidly the values change over time. While growth rates provide a simple measure of how much things change from the beginning of the period to the end, they mask anything that occurs in the middle. For these reasons, SUFG generally uses all three methods for presenting the major forecast projections.

[1] Load diversity occurs because the peak demands for all utilities do not occur at the same time. SUFG estimates the amount of load diversity by analyzing the actual historical load patterns of the various utilities in the state.

Chapter 3

Indiana Projections of Electricity Requirements, Peak Demand, Resource Needs and Prices

Introduction

This chapter presents the forecast of future electricity requirements and peak demand, including the associated new resource requirements and price implications. This report includes three scenarios of future electricity demand and supply: base, low, and high. The base scenario is developed from a set of exogenous macroeconomic assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG includes low and high growth macroeconomic scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first.

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 0.67 percent for electricity requirements and 0.60 percent for peak demand. As shown in Table 3-3, the overall growth rate for electricity sales in this forecast is about 0.21 percent lower than the 2018 forecast update. The 2019 forecast grows more slowly than the previous ones, primarily due to less optimistic economic projections. Lower growth is seen in all three sectors (residential, commercial and industrial). See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also lower than that projected in the previous forecasts. Forecast peak demand growth is lower than that of electricity requirements (0.60 versus 0.67 percent). Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is about 125 MW compared to about 190 MW per year in the 2018 update.

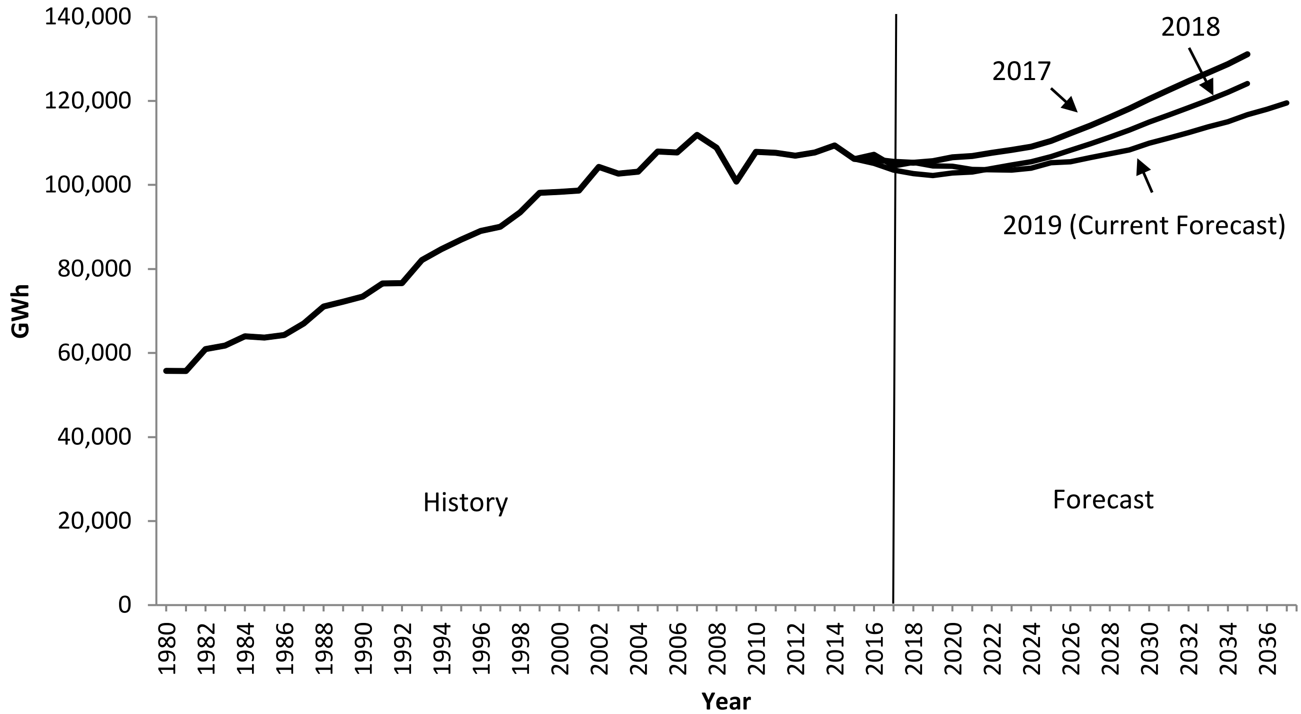
Demand-Side Resources

Beginning with the 2017 forecast, SUFG adjusted the manner in which demand response (DR) programs are modeled and how they are reported. This was necessitated due to the manner in which DR is modeled within Aurora. DR programs are now treated as a resource within the modeling system; previously an adjustment of peak demand was done to account for them outside the utility simulation model. Thus, the peak demand numbers reported in this report have not been adjusted for DR, while the existing resource numbers now include them. DR programs are projected to remain around 1,600 MW over the forecast horizon. As in the past, energy efficiency (EE) programs are treated as a reduction in demand. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 180 MW at the beginning of the forecast period and by about 800 MW at the end of the forecast. See Chapter 4 for additional information about DR and EE.

Table 3-1. Indiana Electricity Requirements Average Compound Growth Rates (Percent)

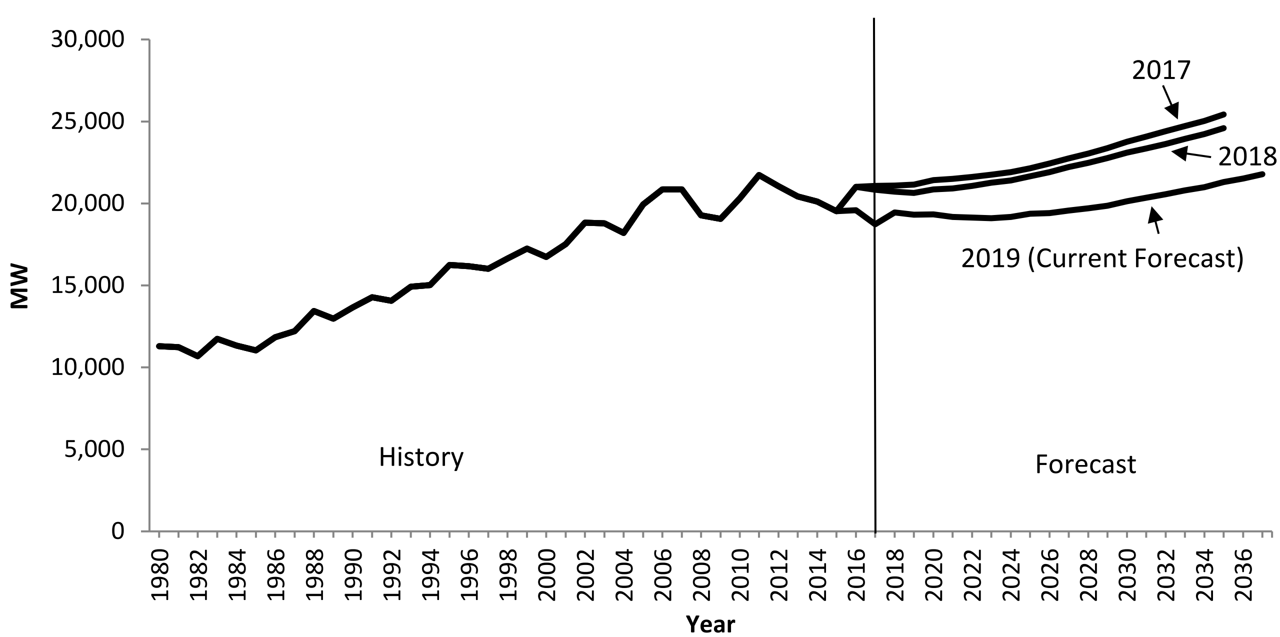
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	0.67	2018-2037
2018	0.88	2016-2035
2017	1.12	2016-2035

Figure 3-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 3-2. Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	0.60	2018-2037
2018	0.83	2016-2035
2017	1.01	2016-2035

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2018 and 2017 Projections)

Sector	Current (2018-2037)	2018 (2016-2035)	2017 (2016-2035)
Residential	0.45	0.54	0.48
Commercial	-0.10	0.38	0.36
Industrial	1.26	1.45	2.04
Total	0.67	0.88	1.12

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales.

SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generating units are added as necessary during the forecast period to maintain a 19.1 percent statewide reserve margin. This level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization and the diversity of peak demand across utilities in the state. Note that the reserve margin incorporated in this forecast is higher than the 18.9 percent figure used in 2018. This is due to a re-estimation of the peak demand diversity based on more recent historical data.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, natural gas-fired combustion turbines and combined cycle units, nuclear, and pulverized coal. Costs and operating characteristics were taken from the Energy Information Administration (EIA), with future reductions in the cost of wind and solar capacity based on data from the National Renewable Energy Laboratory (NREL). Due to data limitations, demand-side resources were not modeled as a selectable resource option. Utility energy efficiency and demand response loads were modeled as fixed quantities based on utility-provided information.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast indicates that the state does not need additional resources until 2024. Since there is little growth in peak demand through the first half of the forecast, new resource needs are driven largely by retirements of existing capacity. Resource needs in the last ten years of the forecast are driven by a combination of increasing demand and additional unit retirements. Despite the lower peak demand projection, the projected additional resource requirements are higher than in previous forecasts in the long term. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report.

In addition to the amount of resources needed to meet the target reserve margin, Table 3-4 shows the resources selected by the optimization model to meet future electricity demand at least cost. This model selects a mix of natural gas-fired combustion turbines and combined cycle units, with wind and solar capacity. Wind capacity is added in the first half of the forecast, solar is added later and natural-gas units are added throughout the forecast.

By 2025, a total of about 3,100 MW of additional resources are selected, of which 1,000 MW is wind powered and the remainder is natural gas-fired. By 2030, 7,800 MW are chosen, of which 2,300 MW is wind powered and the remainder is natural gas-fired. At the end of the forecast horizon in 2037, over 10,000 MW of natural gas capacity, 2,300 MW of wind and 1,300 MW of solar are included, for a total of nearly 14,000 MW.

While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

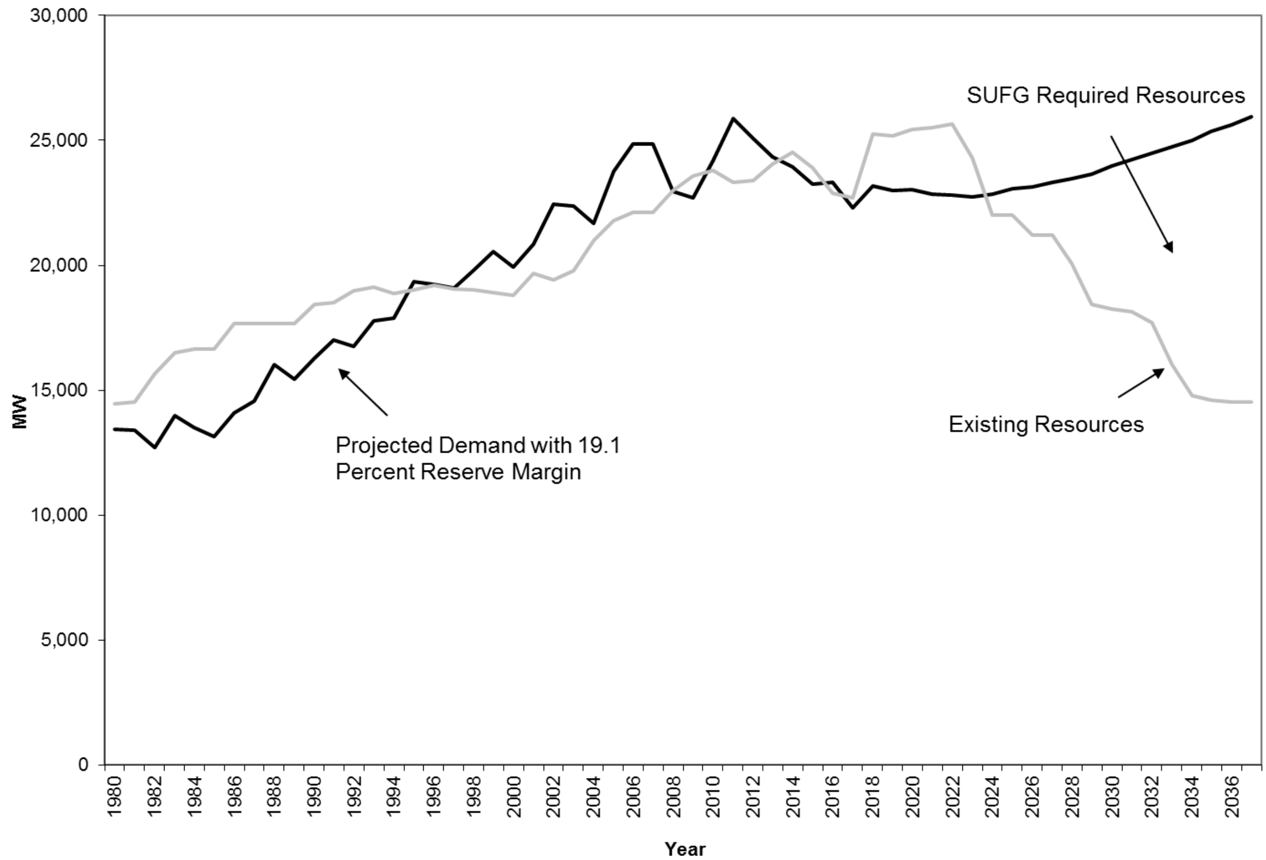
Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of historical data was 2017. Therefore, 2018 and 2019 numbers do not include short term purchases and any longer term purchases of which SUFG was not aware at the time the forecast was prepared.

Table 3-4. Indiana Resource Plan in MW (SUFG Base)

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]					Reserve Margin[6] (percent)
					CT	CC	Wind	Solar	Total	
2018	19,444	25,271		0	0	0	0	0	0	30
2019	19,314	25,175	-96	0	0	0	0	0	0	30
2020	19,326	25,429	254	0	0	0	0	0	0	32
2021	19,184	25,500	71	0	0	0	0	0	0	33
2022	19,138	25,645	145	0	0	0	0	0	0	34
2023	19,105	24,315	-1,329	0	0	23	0	0	23	27
2024	19,169	22,014	-2,301	818	211	1,081	0	0	1,292	22
2025	19,376	22,015	1	1,063	578	1,566	1,000	0	3,144	25
2026	19,417	21,189	-826	1,938	584	2,164	2,000	0	4,748	24
2027	19,572	21,190	0	2,123	922	2,330	2,323	0	5,575	26
2028	19,711	20,065	-1,124	3,413	1,172	2,344	2,323	0	5,839	21
2029	19,862	18,442	-1,623	5,215	2,130	2,853	2,323	0	7,306	19
2030	20,139	18,243	-199	5,745	2,265	3,248	2,323	0	7,836	19
2031	20,346	18,131	-112	6,103	2,265	3,605	2,323	0	8,193	19
2032	20,562	17,719	-412	6,772	2,637	3,902	2,323	0	8,862	19
2033	20,787	16,009	-1,710	8,750	3,009	5,509	2,323	0	10,841	19
2034	20,997	14,799	-1,210	10,211	3,425	6,554	2,323	0	12,301	19
2035	21,296	14,589	-210	10,777	3,425	6,595	2,323	750	13,092	19
2036	21,521	14,539	-50	11,095	3,425	6,681	2,323	1,081	13,510	19
2037	21,781	14,514	-25	11,430	3,425	6,837	2,323	1,337	13,921	19

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.
6 The reserve margin reflects existing and approved resources plus additional selected resources, after adjusting for the expected availability of intermittent resources at the time of peak demand.

Figure 3-3. Indiana Total Demand and Supply in MW (SUFG Base)



Equilibrium Price and Energy Impact

The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop, as described in Chapter 2. The impact of this feature on the forecast of electricity requirements can be significant if price changes are large.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 35 percent from 2017 to 2026 and then slowly decrease by 8 percent until the end of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

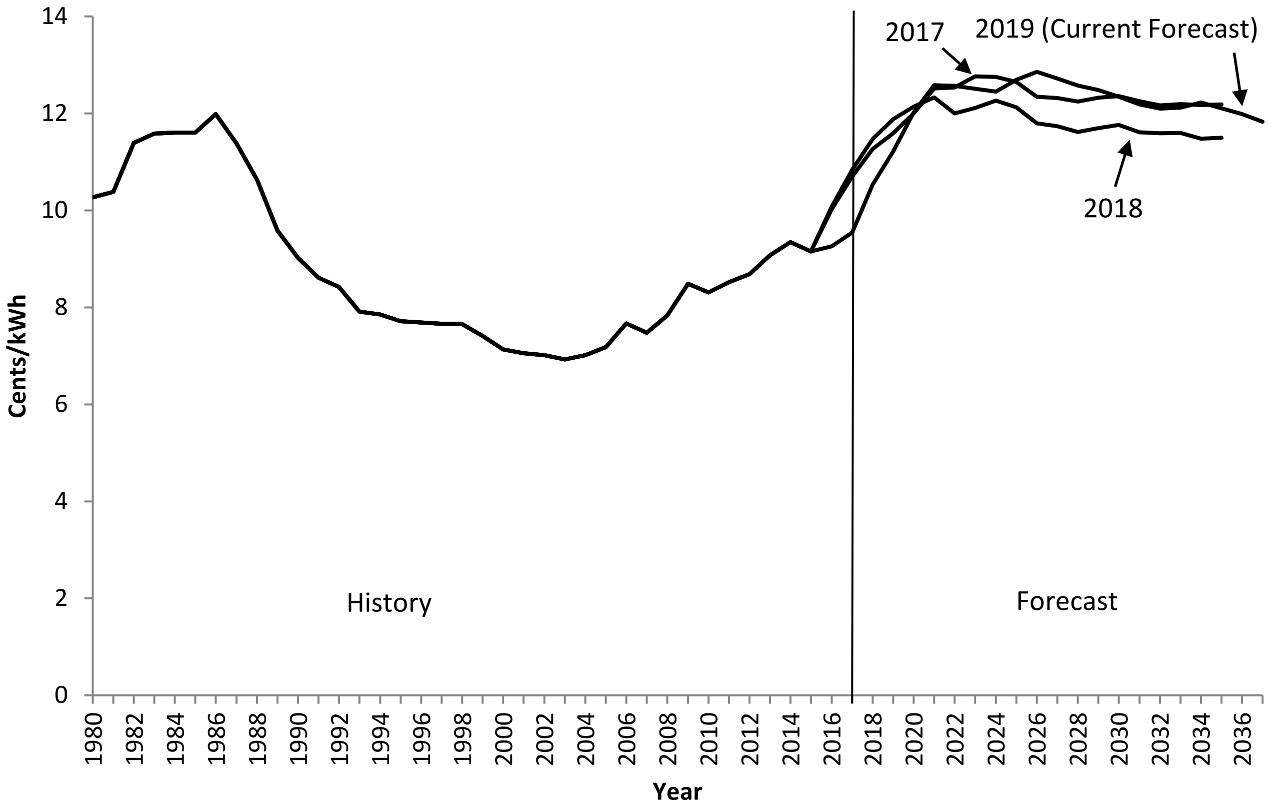
SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2017" is the base case projection contained in SUFG's 2017 forecast and the one labeled "2018" is the base case projection from SUFG's 2018 forecast update. For the prior price forecasts, SUFG rescaled the original price projections to 2017 dollars (from 2015 dollars) using the personal consumption deflator from the CEMR macroeconomic projections.

Table 3-5. Indiana Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	0.61	2018-2037
2018	0.69	2016-2035
2017	1.03	2016-2035

A number of factors determine the price projections in Figure 3-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Figure 3-4. Indiana Real Price Projections in cents/kWh (2017 Dollars) (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for energy requirements for the low and high scenarios are 0.28 percent lower and 0.35 percent higher than the base scenario. These differences are due to economic growth assumptions in the scenario-based projections.

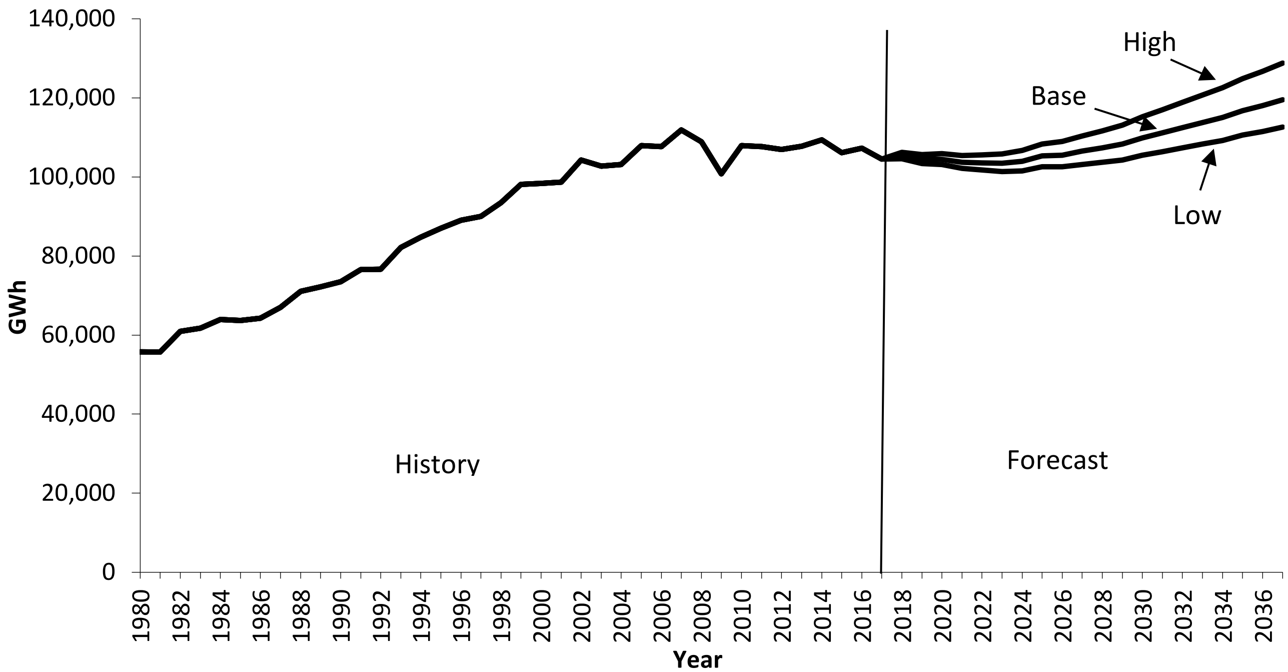
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the shows the resources selected by the optimization model for each scenario. Approximately 15,600 MW over the horizon are added in the high scenario compared to 12,700 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about five percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

Table 3-6. Indiana Electricity Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2018-2037	0.67	0.39	1.02

Figure 3-5. Indiana Electricity Requirements by Scenario in GWh

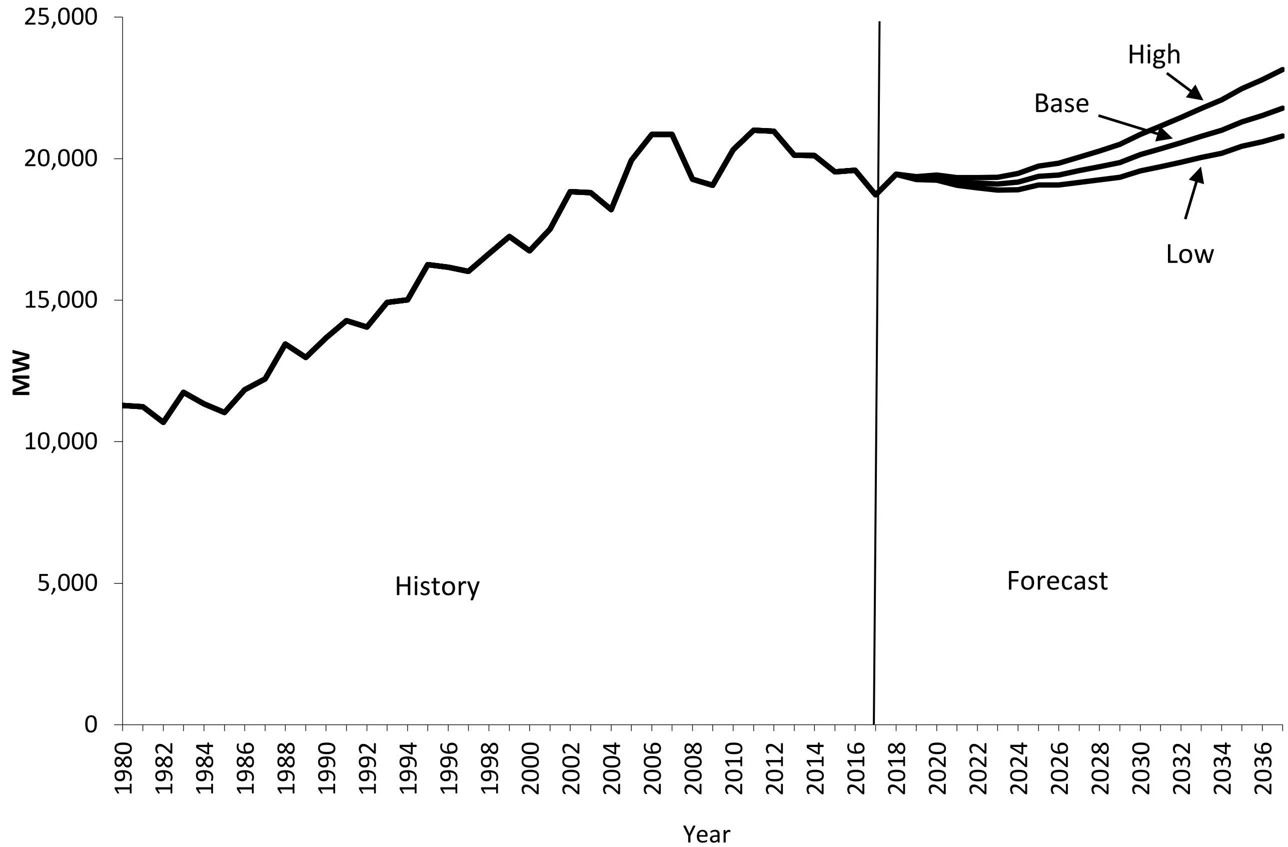


Note: See the Appendix to this report for historical and projected values.

Table 3-7. Indiana Peak Demand Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2018-2037	0.60	0.35	0.92

Figure 3-6. Indiana Peak Demand Requirements by Scenario in MW



Note: See the Appendix to this report for historical and projected values.

Table 3-8. Indiana Selected Resources by Scenario in MW

Year	Base					High					Low				
	CT	CC	Wind	Solar	Total	CT	CC	Wind	Solar	Total	CT	CC	Wind	Solar	Total
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	23	0	0	23	0	26	0	0	26	0	21	0	0	21
2024	211	1,081	0	0	1,292	452	1,183	0	0	1,635	47	1,008	0	0	1,055
2025	578	1,566	1,000	0	3,144	538	1,830	1,000	0	3,368	413	1,301	1,000	0	2,714
2026	584	2,164	2,000	0	4,748	560	2,650	2,000	0	5,210	480	1,810	2,000	0	4,290
2027	922	2,330	2,323	0	5,575	882	2,877	2,177	0	5,937	822	2,011	2,336	0	5,170
2028	1,172	2,344	2,323	0	5,839	1,261	2,890	2,177	0	6,329	1,015	2,027	2,336	0	5,378
2029	2,130	2,853	2,323	0	7,306	2,282	3,482	2,177	0	7,941	1,867	2,496	2,336	0	6,699
2030	2,265	3,248	2,323	0	7,836	2,522	3,857	2,177	0	8,556	1,959	2,868	2,336	0	7,163
2031	2,265	3,605	2,323	0	8,193	2,522	4,321	2,177	0	9,020	1,959	3,160	2,336	0	7,456
2032	2,637	3,902	2,323	0	8,862	2,987	4,635	2,177	0	9,800	2,267	3,451	2,336	0	8,054
2033	3,009	5,509	2,323	0	10,841	3,298	6,412	2,177	0	11,887	2,796	4,826	2,336	0	9,958
2034	3,425	6,554	2,323	0	12,301	3,709	7,575	2,177	0	13,462	3,212	5,804	2,336	0	11,353
2035	3,425	6,595	2,323	750	13,092	3,709	7,618	2,177	903	14,407	3,212	5,849	2,336	648	12,046
2036	3,425	6,681	2,323	1,081	13,510	3,709	7,684	2,177	1,426	14,996	3,212	5,924	2,336	888	12,361
2037	3,425	6,837	2,323	1,337	13,921	3,709	7,873	2,177	1,794	15,553	3,212	6,022	2,336	1,121	12,692

Chapter 4

Major Forecast Inputs and Assumptions

Introduction

The models SUFG utilizes to project electric energy sales, peak demand and prices require external, or exogenous, assumptions for several key inputs. Some of these input assumptions pertain to the level of economic activity, population growth and age composition for Indiana. Other assumptions include the prices of fossil fuels, which are used to generate electricity and compete with electricity to provide end-use service. Also included are estimates of the energy and peak demand reductions due to utility demand-side management programs.

This section describes SUFG's scenarios, presents the major input assumptions and provides a brief explanation of forecast uncertainty.

Macroeconomic Scenarios

The assumptions related to macroeconomic activity determine, to a large degree, the essence of SUFG's forecasts. These assumptions determine the level of various activities such as personal income, employment and manufacturing output, which in turn directly influence electricity consumption. Due to the importance of these assumptions and to illustrate forecast uncertainty, SUFG used alternative projections or scenarios of macroeconomic activity provided by the Center for Econometric Model Research (CEMR) at Indiana University.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

These scenarios are developed by varying the major forecast assumptions, i.e., Indiana's share of the national economy.

Economic Activity Projections

National and state economic projections are produced by CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2019 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

CEMR developed these projections from its U.S. and Indiana macroeconomic models. The Indiana economic forecast is generated in two stages. First, a set of exogenous assumptions affecting the national economy are developed by CEMR and input to its model of the U.S. economy. Second, the national economic projections from this model are input to the Indiana model that translates the national projections into projections of the Indiana economy.

The CEMR model of the U.S. economy is a large scale quarterly econometric model. Successive versions of the model have been used for more than 15 years to generate short-term forecasts. The model has a detailed aggregate demand sector that determines output. It also has a fully specified labor market submodel. Output determines employment, which then affects the availability of labor. Labor market tightness helps determine wage rates, which, along with employment, interest rates and several other variables determine personal income. Fiscal policy variables, such as spending levels and tax rates, interact with income to determine federal, state and local budgets. Monetary policy variables interact with output and price variables to determine interest rates.

A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy.

The Indiana model has four main modules. The first disaggregates total U.S. employment into manufacturing and non-manufacturing sectors. The second module then projects the share of each industry in Indiana. Additional relationships are used to project average weekly labor hours and average hourly earnings by industry. These are used with employment to calculate a total wage bill. The third module projects the remaining components of personal income. In the fourth module, labor productivity combined with employment projections is used to calculate real Gross State Product (GSP), or output, by industry.

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from "Long-Range Projections 2018-2039" [CEMR] are:

"Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income increases 10 percent, while the payroll tax rate rises by 1.7 percent. Corporate rates are assumed to remain constant at their new lower level. Federal grants to state and local governments are assumed to grow at a 4.9 percent rate early in the projection period, rising to 5.3 percent toward the end. Growth in government purchases is low. This produces a reduction in the federal government deficit from 4.8 percent of GDP in 2018 to 3.7 percent at the end of the projection period. By comparison over the period 1960-1999 the deficit averaged 2.8 percent of GDP.

State and local tax rates rise through the projection period, by a total of 2.5 percent. This allows these governments to have budgets that move from a 2018 deficit amounting to 1.1 percent of GDP to 0.4 percent of GDP by 2039.

Real exports are assumed to grow at about 4.1 percent through the projection period. This roughly matches growth of imports, resulting in a nominal net export deficit that is relatively stable in dollar terms. As a result, the deficit declines from 3.0 percent of GDP in 2018 to just above 1.3 percent in 2039."

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 2.40 percent and U.S. employment growth averages 0.83 percent over the 2018 to 2037 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.72 percent from 2018 through 2037. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 1.73 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to grow at a 0.95 percent annual rate over the forecast horizon.

Despite a small decline in manufacturing employment (at an average annual rate of -0.57 percent), manufacturing GSP (the industrial sector model driver) is expected to rise at a 2.01 percent annual rate as gains in productivity far outpace the drop in employment.

A summary comparison of CEMR's projections used in SUFG's previous and current electricity projections and historical growth rates for recent historical periods is provided in Table 4-1. It should be noted that some historical data has been revised by CEMR based on changes from federal sources, particularly the Bureau of Economic Analysis.

To capture some of the uncertainty in energy forecasting, CEMR provided low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of real personal income is increased by about 0.30 percent per year (to 2.03 percent), non-manufacturing employment growth increases 0.10 percent (to 1.05 percent) while Indiana real manufacturing GSP growth is increased by 0.86 percent (to 2.86 percent). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.43, 0.84 and 1.18 percent, respectively).

Demographic Projections

Household demographic projections are a major input to the residential energy forecasting model. The SUFG forecasting system includes a housing model which utilizes population and income assumptions to project households or customers.

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The IBRC population growth forecast for Indiana is 0.36 percent per year on average for the period of 2015-2035. This projection is based on the 2010 Census and includes projections of county population by age group. The fastest growing age groups are those of seniors age 65+ (2.12 percent) and preschool 0-4 (0.33 percent). College age (20-24) are projected to decline at an annual rate of 0.44 percent. Older adults aged 45-64 are projected to decline at an annual rate of 0.37 percent. Population growth in total is low during the projection period because the age distribution in Indiana is skewed from young adults of childbearing age to older adults with higher mortality rates.

Indiana population growth has slowed markedly in recent years. The number of people over age 65 (the groups with fewer occupants per household) is projected to grow more rapidly than the younger population. Thus, the number of people per household is projected to decline and household formations are expected to grow more rapidly than total population.

The historical growth of household formations (number of residential customers) has slowed significantly from slightly over 2 percent during the late 1960s and early 1970s to 0.4 percent from 2005-2017. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.09 percent over the forecast period.

Table 4-1. Growth Rates for CEMR Projections of Selected Economic Activity Measures (Percent)

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2017	Feb 2018	Feb 2019
	1990-1995	1995-2000	2000-2005	2005-2010	2010-2017	2016-2035	2016-2035	2018-2037
United States								
Real Personal Income	2.47	4.77	2.00	1.44	2.76	2.35	2.20	2.29
Total Employment	1.40	2.37	0.30	-0.56	1.69	0.77	0.84	0.83
Real Gross Domestic Product	2.57	4.32	2.58	0.90	2.11	2.53	2.42	2.40
Personal Consumer Expenditure Deflator	2.54	1.73	2.10	1.97	1.48	1.92	1.94	2.06
Indiana								
Real Personal Income	2.87	4.43	0.68	1.13	2.44	1.86	1.68	1.73
Employment								
Total Establishment	2.03	1.50	-0.29	-1.12	1.49	0.66	0.74	0.72
Manufacturing	1.47	0.35	-2.99	-4.79	2.51	-0.55	-0.25	-0.57
Non-Manufacturing	2.23	1.76	0.47	-0.05	1.24	0.87	0.91	0.95
Real Gross State Product								
Total	5.83	4.78	1.60	0.67	1.21	2.47	2.37	2.31
Manufacturing	7.95	4.68	2.01	2.34	-0.01	2.98	2.83	2.01
Non-Manufacturing	4.86	4.84	1.45	0.00	1.71	2.25	2.17	2.42

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: The growth rates for manufacturing and total GSP do not reflect the adjustment made by SUFG to the transportation equipment industry forecast as described later in this chapter.

Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. About 65% of the state's electricity was still generated from coal in 2018.[1] Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

SUFG's modeling system incorporates separate fuel price projections for utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used February 2019 fossil fuel price projections from EIA for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2017 dollars/mmBtu), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.
- Natural gas prices decreased significantly from 2008 to 2012. Prices then rebounded slightly in

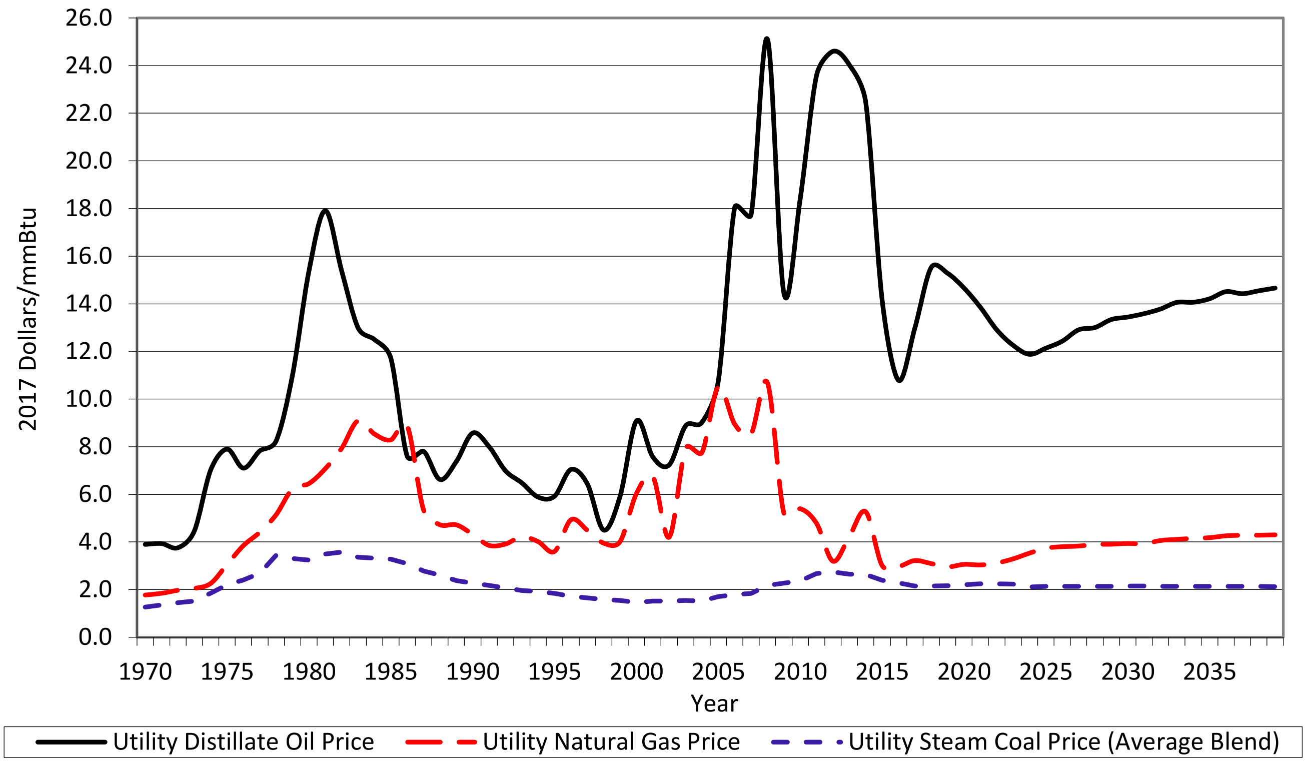
[1] Source: Indiana Utility Regulatory Commission 2019 Annual Report, available at https://www.in.gov/iurc/files/20190910101209630.pdf

2013 and 2014 before another dip in 2015 and 2016. Natural gas price is projected to increase gradually for the remainder of the forecast horizon.

- Distillate prices also decreased significantly in 2009 from the high prices of 2008. Prices then rebounded significantly through 2012 before declining again in 2013, followed by substantial decreases in 2016. They rebounded quickly in 2017 and 2018. Distillate price is projected to decline in 2024, then grow at a slower pace over the remainder of the forecast horizon.

The fossil fuel price projections for the utility sector are presented in Figure 4-1. The general trajectories for the other sectors are similar.

Figure 4-1. Utility Real Fossil Fuel Prices



Demand-Side Management, Energy Efficiency and Demand Response

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's load shape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand from periods of high system demand to times when overall system demand is lower. SUFG considers separately the two components of DSM: energy efficiency (EE), which affects both energy and peak demand, and demand response (DR), which generally affects peak demand but has little impact on energy.

Incremental energy efficiency, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are modeled within Aurora by effectively changing the utility's demand by the appropriate level of energy and peak demand for the EE program. EE programs that were in place in 2017 are considered to be embedded in the calibration data, so no adjustments are necessary.

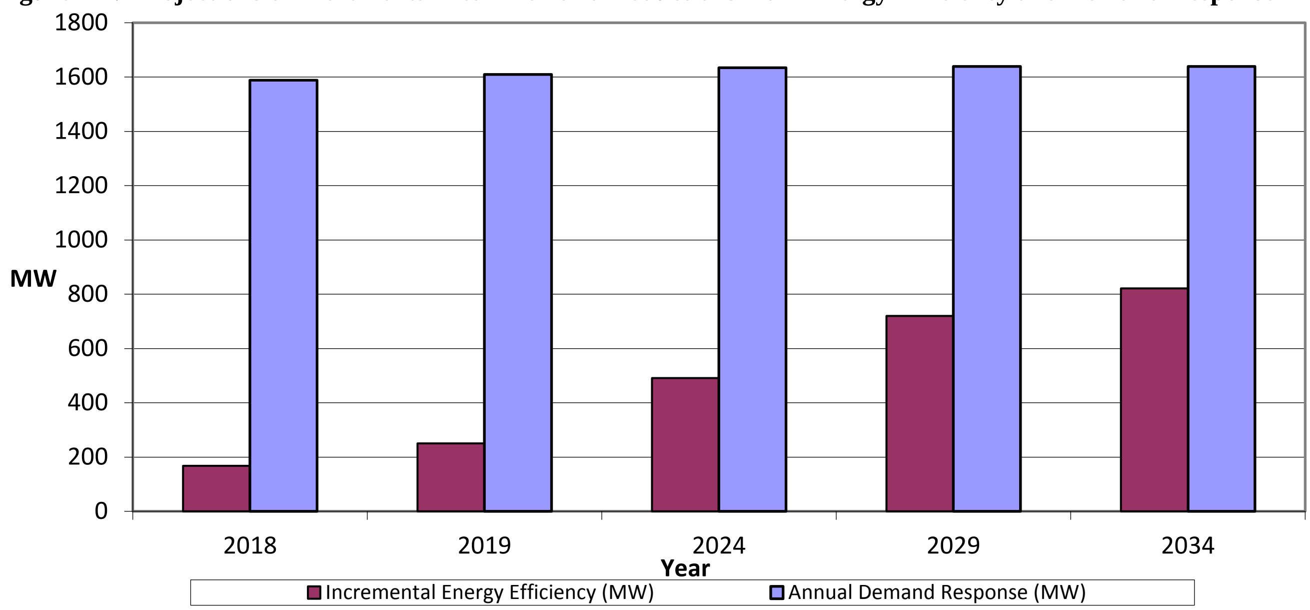
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. DR is typically treated differently than energy efficiency. In previous forecasts, the amount of demand response was subtracted from the utility's peak demand in order to determine the amount of new capacity required. Beginning with the 2017 forecast, demand response is modeled within Aurora as a resource instead of as an after-the-fact adjustment as explained in Chapter 2.

Table 4-2 shows the peak demand reductions from embedded DSM in 2017 and from incremental EE and annual DR available in 2018 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings, from utility filings with the federal Energy Information Administration (EIA) and from information collected by SUFG directly from the utilities. SUFG does not attempt to project additional DSM savings beyond those identified by the utilities at the time this report was prepared. It should be noted that SUFG does not advocate any specific means for meeting future resource requirements, with additional energy efficiency being one of the options available for meeting those requirements. Figure 4-2 shows projected values of peak demand reductions for incremental energy efficiency and demand response for 2018 and at five-year intervals starting in the year 2019.

Table 4-2. 2017 Embedded DSM and 2018 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs (MW)

2017 Embedded DSM	2018 Incremental Energy Efficiency	2018 Annual Demand Response
685	167	1,589

Figure 4-2. Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



Changes in Forecast Drivers from 2017 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. This section compares the CEMR's projections used in SUFG's 2017 and 2019 forecasts.

In the time between CEMR's February 2017 (herein referred to as CEMR2017) and February 2019 (CEMR2019) long-range projections, the U.S. economy continued recovering steadily. Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2013 through 2020 and for 2025, 2030, and the last year of the forecast period 2037. The tables show long-run projections of real values and percentage change at annual rates for non-manufacturing employment, real personal income, and total real manufacturing GSP. The tables also show the percentage change between CEMR2017 and CEMR2019. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2011 through 2039. Some of the historical values differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

CEMR forecasts employment at the sectoral level, separating employment into sectors for durable goods manufacturing, non-durable goods manufacturing, and non-manufacturing. Analyzing the non-manufacturing (or service) sector's employment provides insight into Indiana's commercial electricity demand.

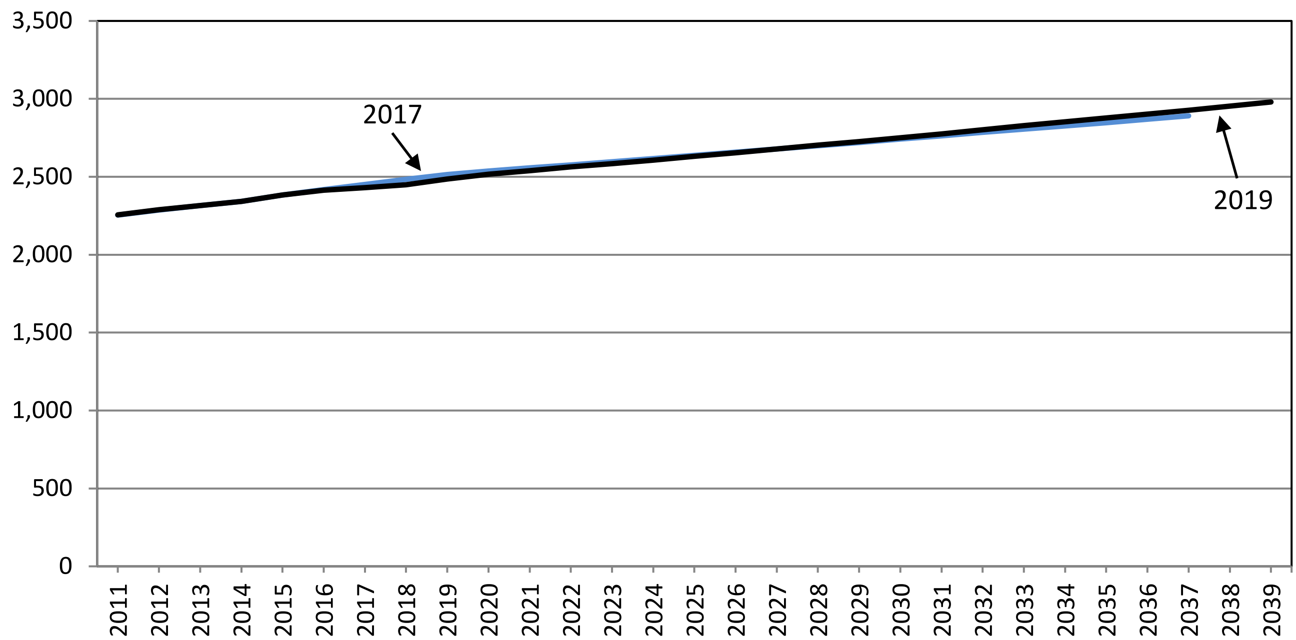
Table 4-3 and Figure 4-3 show that the current CEMR projection for non-manufacturing employment is very close to that in 2017 projection. In short term, the CEMR2019 projection is slightly lower than that of the CEMR2017. However, the projection in CEMR2019 surpasses that in CEMR2017 starting from 2027.

Table 4-3. 2017 and 2019 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2037**
	Thousands of persons										
CEMR 2017	2314.50 (1.19)	2342.08 (1.19)	2382.69 (1.73)	2416.93 (1.44)	2450.17 (1.38)	2483.98 (1.38)	2514.66 (1.23)	2537.34 (0.90)	2638.25 (0.81)	2741.41 (0.78)	2891.13 (0.76)
CEMR 2019	2315.29 (1.20)	2342.39 (1.17)	2382.55 (1.71)	2414.14 (1.33)	2431.13 (0.70)	2448.45 (0.71)	2486.03 (1.53)	2517.19 (1.25)	2630.78 (0.90)	2750.91 (0.89)	2927.73 (0.88)
Percentage change between two projections	0.03	0.01	-0.01	-0.12	-0.78	-1.43	-1.14	-0.79	-0.28	0.35	1.27

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-3. Indiana Non-manufacturing Employment (thousands of people)



Real Personal Income

Real personal income provides an important picture of the impacts of the economy on Indiana. Changes in real personal income will directly influence electricity demand. Real personal income is an input to the residential energy forecasting model.

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2019 has a slightly stronger projection for real personal income before 2026, but a weaker projection beginning in 2026 compared with CEMR2017. CEMR2019 indicates real personal income $4.65 billion (1.15 percent) lower than that in CEMR2017 by the end of the forecast period.

Figure 4-4 illustrates that the CEMR2019 real personal income is projected to be lower than CEMR2017 beginning in 2026 to the end of the forecast horizon.

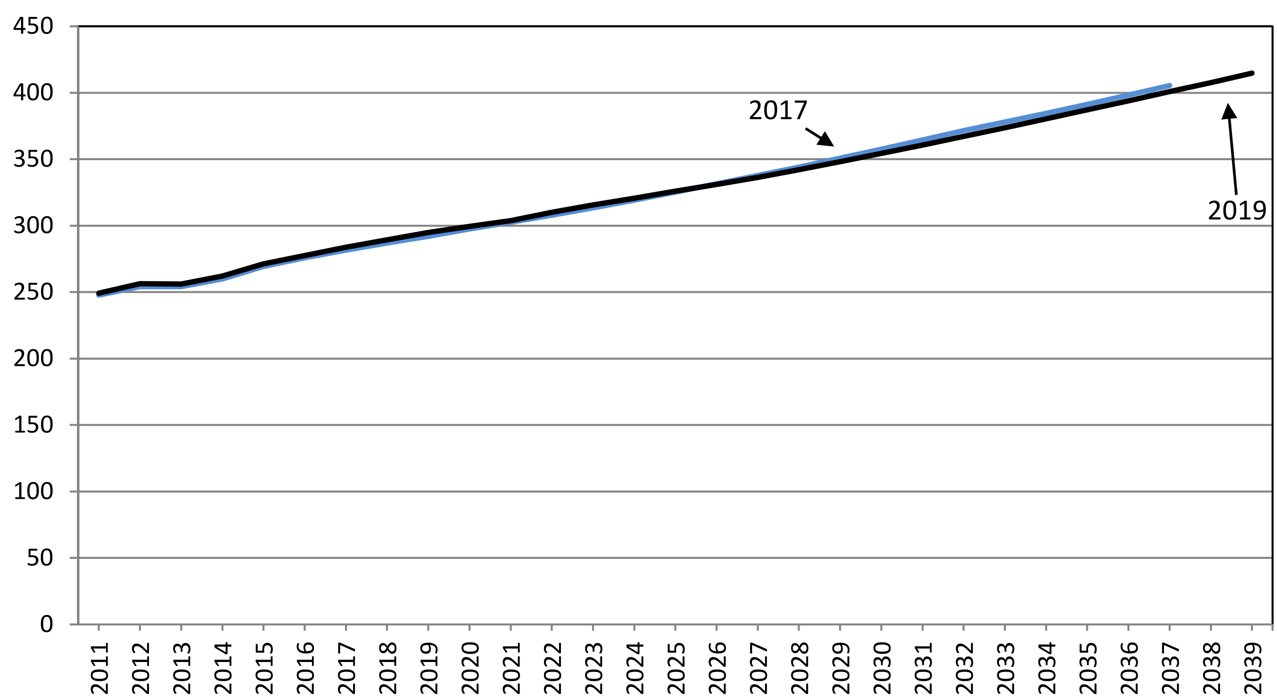
Table 4-4. 2017 and 2019 CEMR Projections for Indiana Real Personal Income

	Year										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2037**
	Billions of 2012 $										
CEMR 2017	254.18 (0.02)	259.92 (2.26)	269.38 (3.64)	275.86 (2.41)	281.73 (2.13)	286.95 (1.85)	292.10 (1.79)	297.52 (1.86)	325.19 (1.86)	357.52 (1.96)	405.40 (1.81)
CEMR 2019	256.08 (-0.06)	262.07 (2.34)	271.23 (3.49)	277.42 (2.28)	283.78 (2.29)	289.35 (1.96)	294.98 (1.95)	299.51 (1.54)	325.83 (1.61)	354.28 (1.79)	400.75 (1.74)
Percentage change between two projections	0.75	0.83	0.69	0.56	0.73	0.84	0.99	0.67	0.20	-0.91	-1.15

Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Projections”

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-4. Indiana Real Personal Income (billions of 2012 dollars)



Real Manufacturing Gross State Product

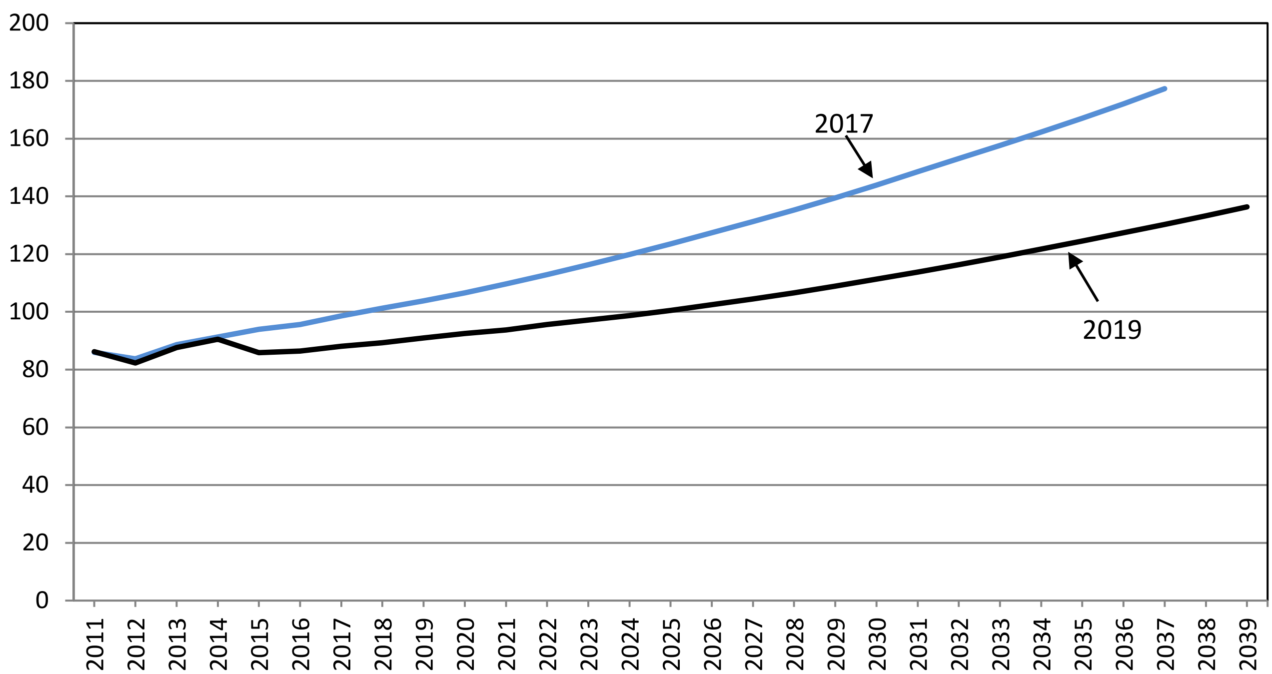
Changes in manufacturing GSP will have significant implications for electricity use in the industrial sector. The recession of 2008-2009 had a larger impact on manufacturing GSP growth than on either non-manufacturing employment or personal income.

Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. As the figure illustrates, the CEMR2019 projection for the entire forecast period is significantly lower than CEMR2017. The projection for 2037 is $46.99 billion (26.50 percent) lower than that in CEMR2017. The major reasons for the lower projection in CEMR2019 are 1) 2018 BEA revision on historic GDP data, 2) change of base year from 2009 to 2012 from CEMR2017 to CEMR2019, and 3) lower values of recent GDP history.

Table 4-5. 2017 and 2019 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2037
	Billions of 2012 $										
CEMR 2017	88.68	91.31	93.96	95.64	98.58	101.29	103.85	106.64	123.56	143.95	177.31
	(5.90)	(2.97)	(2.90)	(1.79)	(3.07)	(2.74)	(2.54)	(2.68)	(3.09)	(3.16)	(3.05)
CEMR 2019	87.59	90.57	85.91	86.46	88.12	89.34	91.00	92.50	100.54	111.31	130.32
	(6.43)	(3.40)	(-5.15)	(0.64)	(1.92)	(1.38)	(1.86)	(1.64)	(1.81)	(2.22)	(2.29)
Percentage change between two projections	-1.22	-0.81	-8.57	-9.60	-10.61	-11.79	-12.37	-13.26	-18.64	-22.67	-26.50
Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Projections”											
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.											

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2012 dollars)



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2017, this sector represented 29 percent of the total real value of products manufactured in the state.

SUFG deemed that CEMR's forecast showed too much growth over the long term for this sector (as in CEMR2015 and CEMR2017 before), so the forecast was again tempered. The "CEMR2019 Adjusted" projection calls for growth over the forecast period 2018-2037 of an annual rate of approximately 2.01 percent.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the adjusted transportation equipment GSP for both CEMR2017 and CEMR 2019. The industry is projected to keep recovering from the recession for the entire forecast period. However, compared with CEMR2017, CEMR2019 projects growth with a slower pace. In 2037, the level forecast in CEMR2019 is 38.24 percent lower than that in CEMR2017.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented approximately 12 percent of Indiana manufacturing GSP in 2017, it accounted for 30 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2017 and 2019 for the primary metals industry. The primary metals industry is projected to be decreasing over the forecasting period of 2018-2037. The CEMR2019 projections for the primary metals industry are higher than the CEMR2017. In 2037, the projected GSP level for the primary metals industry in the CEMR2019 is about 36 percent higher than that in the CEMR2017.

Table 4-6. 2017 and 2019 Adjusted CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2037**
	Billions of 2012 $										
CEMR 2017 Adjusted	17.92	18.50	19.03	19.37	19.97	20.52	21.04	21.60	25.03	29.16	35.92
	(5.45)	(3.23)	(2.90)	(1.79)	(3.07)	(2.74)	(2.54)	(2.68)	(3.09)	(3.16)	(3.05)
CEMR 2019 Adjusted	13.63	14.29	14.18	14.72	15.00	15.21	15.49	15.74	17.11	18.95	22.18
	(3.23)	(4.85)	(-0.78)	(3.79)	(1.92)	(1.38)	(1.86)	(1.64)	(1.81)	(2.22)	(2.29)
Percentage change between two projections	-23.93	-22.73	-25.50	-24.04	-24.89	-25.88	-26.37	-27.11	-31.63	-35.02	-38.24

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Table 4-7. 2017 and 2019 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2037**
	Billions of 2012 $										
CEMR 2017	7.69	7.15	6.87	6.28	5.90	5.56	5.23	4.92	4.94	4.98	4.96
	(28.88)	(-6.95)	(-3.94)	(-8.55)	(-6.12)	(-5.74)	(-5.92)	(-5.88)	(0.19)	(0.21)	(-0.05)
CEMR 2019	10.00	9.37	11.07	11.95	10.86	10.13	9.41	8.64	6.94	6.83	6.74
	(27.76)	(-6.28)	(18.18)	(7.89)	(-9.13)	(-6.68)	(-7.09)	(-8.27)	(-0.55)	(-0.17)	(-0.21)
Percentage change between two projections	30.07	31.02	61.19	90.16	84.06	82.22	79.95	75.37	40.47	37.17	36.00

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

1. exogenous assumptions;
2. stochastic model error; and,
3. non-stochastic model error.

Projections of future electricity requirements are conditional on the projections of exogenous variables. Exogenous variables are those for which values must be assumed or projected by other models or methods outside the energy modeling system. These exogenous assumptions, including demographics, economic activity and fossil fuel prices, cannot known with certainty. Thus, they represent a major, unavoidable source of uncertainty in any energy forecast.

Stochastic error is inherent in the structure of any forecasting model. Sampling error is one source of stochastic error. Each set of observations (the historical data) from which the model is estimated constitutes a sample. When one considers stochastic model error, it is implicitly assumed that the model is correctly specified and that the data is correctly measured. Under these assumptions the error between the estimated model and the true model (which is always unknown) has certain properties. The expected value of the error term is equal to zero. However, for any specific observation in the sample, the error term may be positive or negative. The errors from a number of samples follow a pattern, which is described as the normal probability distribution, or bell curve. This particular normal distribution has a zero mean, and an unknown, but estimable variance. The magnitude of the stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance, the larger the potential error will be.

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods. SUFG is committed to identifying and correcting potential errors in model specification, data measurement, and appropriate estimation methods.

References

Center for Econometric Model Research, "Long-Range Projections 2018-2039," Indiana University, February 2019.

Energy Information Administration, "Annual Energy Outlook 2019", February 2019.

Indiana Utility Regulatory Commission, "2019 Annual Report", September 2019.

Chapter 5

Residential Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project residential electricity sales. These different modeling approaches have specific strengths and complement each other. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been updated periodically. After the release of the 2007 SUFG Indiana Electricity Projections report, SUFG acquired a proprietary end-use model, Residential Energy Demand Model System (REDMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REDMS was obtained to replace an older residential sector end-use oriented model known as REEMS. Both end-use models are descendants of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Starting with the 2011 forecast, SUFG adopted REDMS as the primary residential sector energy model, and it is used to project residential electricity sales in this forecast. REDMS is actively support by the vendor, Jerry Jackson Associates. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model residential energy for the not-for-profit utilities (NFPs) with an econometric approach.

SUFG chose REDMS as the primary residential sector energy projection model for three reasons. First, the SUFG econometric model divides customers into two distinct classes depending upon the space heating fuel employed: electricity and other fuels. Over time the distinction between electric space heating and natural gas (or liquefied petroleum gas) space heating has blurred due to the emergence and acceptance of hybrid systems.

Second, at least one major Indiana utility no longer offers a specific electric rate schedule to new customers that choose to use electricity for space heating. Also, at least one additional Indiana utility offers a restricted electric space heating rate which is dependent upon equipment efficiency criteria.

Third, federal law mandated lighting efficiency standards which SUFG felt were best modeled in a direct end-use context. The standards called for a 30 percent improvement in lighting efficiency beginning in 2012 with a phased in efficiency improvement of 60 percent by 2020. Econometric methods work reasonably well to capture trends in efficiency over time, but the lighting standards were more aggressive than historical equipment standards in both the level and timing of the mandated efficiency improvements. For this reason SUFG did not feel comfortable relying on the traditional econometric energy model and chose the direct end-use modeling approach rather than make adjustments to the econometric model projections.

Historical Perspective

The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of five recent periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions. Beginning in 2008 economic activity slowed dramatically. Due in large part to economic weakness, low electric energy sales growth was experienced in the residential sector (see Figure 5-1).

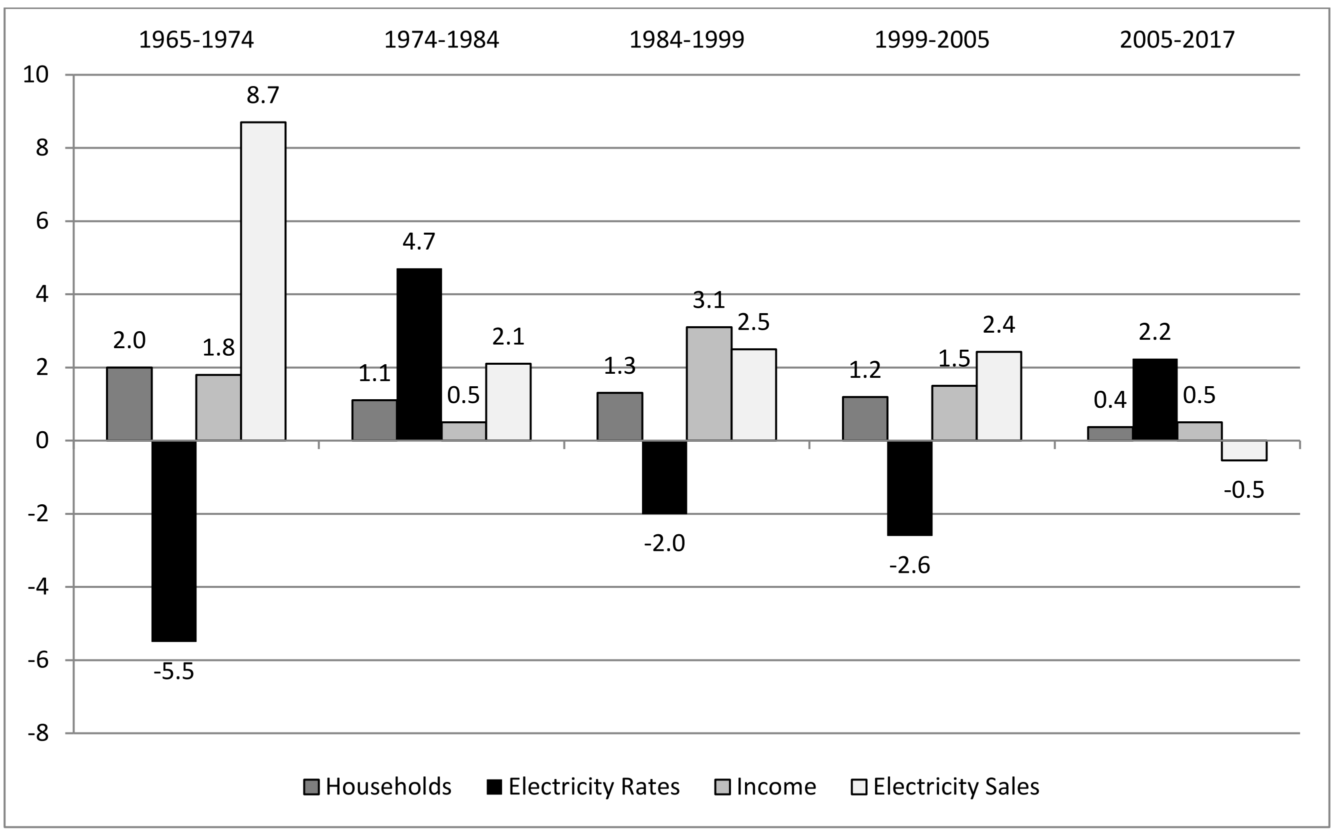
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (almost 2 percent per year in real terms). This period also was marked by a boom in the housing industry as the number of residences increased at an average rate of 2 percent per year. In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during 1979-1981, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. This resulted in a swing in electric prices of more than 10 percent. Growth in real household income was a miniscule 0.5 percent, less than one-third of that seen in the previous period. The housing market also went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices is reflected in the dramatic decline in the growth of residential electricity sales from nearly 9 percent per year 1965-1974, to just over 2 percent per year for the next decade. Events turned again during the mid-1980s. Real household income grew at more than the pre-embargo rate, 3.1 percent per year. Real electricity prices declined 2.0 percent per year at one third the pre-embargo rate. Households grew at only a slightly higher rate than in the post-embargo decade, about 1.3 percent per year. Despite these more favorable market conditions, annual electricity sales growth increased only 0.4 percent to 2.5 percent per year.

Several market factors contributed to the small difference in sales growth between the post-embargo and more recent period. First and perhaps most importantly, is the difference in the availability and price of natural gas between the two periods. Restrictions on new natural gas hook-ups during the post-embargo period and supply uncertainty caused electricity to gain market share in major end-use markets previously dominated by natural gas, i.e., space heating and water heating. More recently, plentiful supply and falling natural gas prices through 1999 caused natural gas to recapture market share. Next in importance are equipment efficiency standards and the availability of more efficient appliances. Appliance efficiency improvement standards did not begin until late in the post-embargo era. Lastly, appliance saturations tend to grow more slowly as they approach full market saturation, and the major residential end uses are nearing full saturation.

From 1999-2005, residential household growth decreased slightly to a 1.2 percent annual rate similar to the 1984-1999 period, real electric rates continued to decline, but the growth in personal income, while positive, slowed markedly. Despite the slow growth in income, electricity sales continued to grow at roughly the rate observed during the 1984-1999 period.

More recently, from 2005-2017, the effects of the economic downturn coupled with rising electricity prices and increased efficiency have resulted in much lower growth in electricity sales. Growth of the number of households slowed to about one-fourth the rate observed over the preceding twenty years. Real electricity prices increased at an average annual rate of 2.2 percent, reversing the trend of the previous twenty years. Real household income increased at only 0.5 percent over the period. The net effect of these changes was to reduce the electricity sales growth rate to essentially flat over the period.

Figure 5-1. State Historical Trends in the Residential Sector (Annual Percent Change)



Model Description

The residential end-use model REDMS is the residential analogue to CEDMS, the commercial sector end-use model described in the next chapter of this report. For this reason the description of REDMS below is nearly identical to that of CEDMS in the commercial sector chapter.

Figure 5-2 depicts the structure of the residential end-use model. As the figure shows, REDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the residential sector as it is for modeling the commercial sector. REDMS divides residential dwellings among three dwelling types. It also divides energy use in each dwelling type among ten possible end uses, including a miscellaneous or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, REDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 5-2.) REDMS also divides dwellings among vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.
REDMS projects energy use for each dwelling vintage according to the following equation:

$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, dwelling type l and vintage t in the forecast year T;

t = dwelling vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/year or Btu/year;

a = fraction of dwelling served by fuel i, end use k, and dwelling type l for dwelling additions of vintage t;

A = dwelling additions by vintage t and dwelling type l; and

d = fraction of dwellings of vintage t still standing in forecast year T.

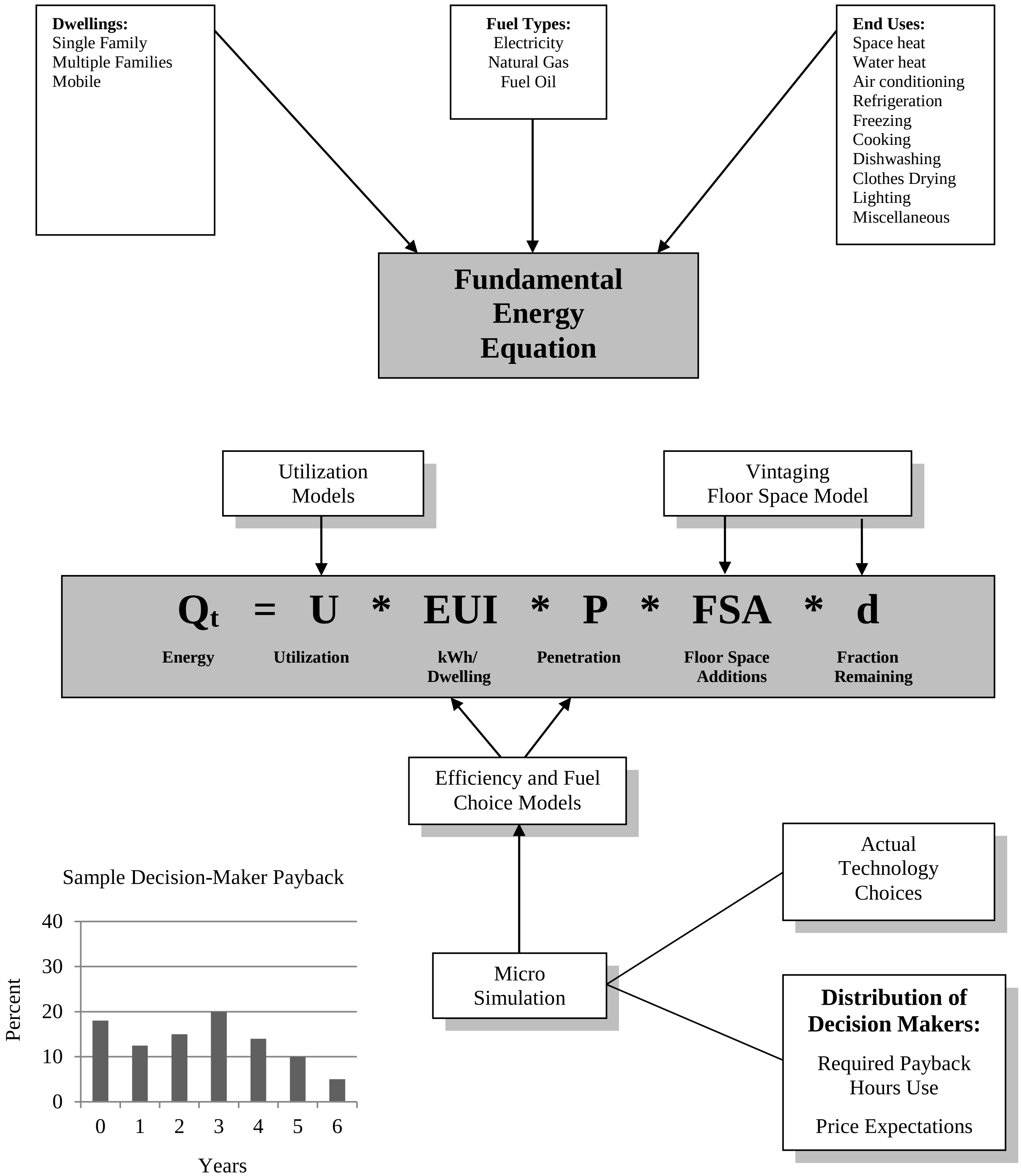
REDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

REDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample decision-makers in the model make choices from a set of discrete equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. REDMS uses the discrete technology choice methodology to model equipment choices for all major end-uses.

Equipment standards are easily incorporated in REDMS' equipment choice sub-models. Besides efficiency and fuel choices, REDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Figure 5-2. Structure of Residential End-Use Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's current residential electricity sales projections. First, the current projection of residential sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current high and low scenario projections. Also, at each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers in the residential end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-1. Electricity consumption increases substantially due to increases in the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an initial space heating (and subsequently water heating) fuel for a new dwelling is chosen retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital expense of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. In the case of dwelling additions, a statistically significant relationship between fuel prices and fuel specific end-use penetrations was not discernable. During the period used for model calibration 1990-2005, electric space heating penetration was remarkably consistent at around 20 percent with natural gas and LPG largely capturing the remainder, real electricity prices were virtually constant, real gas and oil prices drifted upward with considerable volatility but did not exhibit any persistent lasting changes in level.

Personal income effects on fuel and efficiency choices are reflected in the decision makers' behavior through the micro-simulation modeling. On average, one would expect those decision makers facing active income or financial constraints to be the decision makers with shorter payback intervals and those without such constraints to have longer payback horizons. Also, a statistically significant relationship between end-use utilization and personal income could not be identified.

Table 5-1. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	9.9
Electric Rates	-4.0

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-2 and Figure 5-3. The growth rate for the current base projection of Indiana residential electricity sales is 0.45 percent, which is 0.09 percent lower than SUFG's 2018 projection of 0.54 percent. The historic and 2019 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection lies below both the 2017 and 2018 projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2017.

Table 5-3 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, customer growth is partially offset by decreases in utilization, which is the amount of energy used per household. Use per household decreases because of increasing prices and the implementation of new efficiency standards. It can also be seen from the table that residential DSM cuts the sales growth rate by approximately one-third, reducing it from 0.68 percent to 0.45 percent.

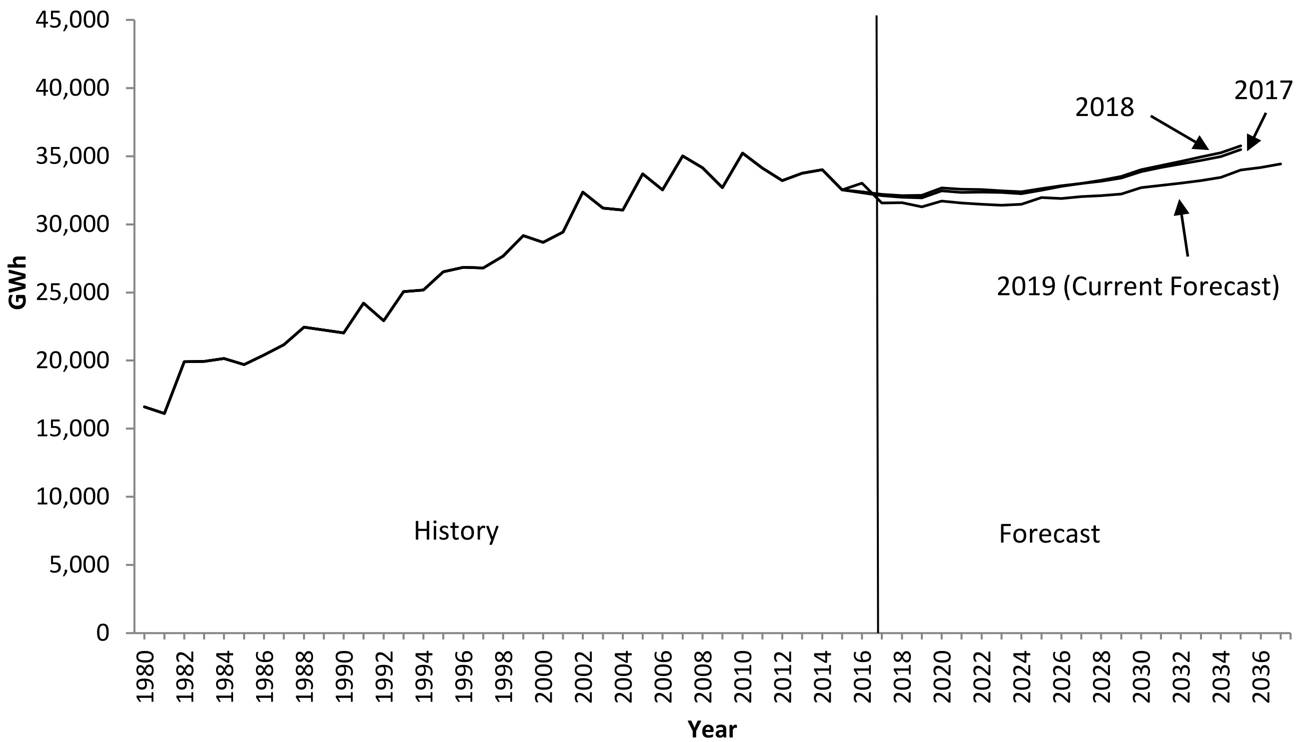
Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2017 and 2018 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all five cases are very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a significant difference in growth rates for the base and high scenarios.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.06 percent higher and 0.04 lower, respectively, than the base scenario. This difference is due primarily to differences in the growth of household income.

Table 5-2. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	0.45	2018-2037
2018	0.54	2016-2035
2017	0.48	2016-2035

Figure 5-3. Indiana Residential Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 5-3. History of SUFG Residential Sector Growth Rates (Percent)

Forecast	No. of Customers	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2019 SUFG Base (2018-2037)	1.09	-0.41	0.68	-0.64	0.45
2018 SUFG Base (2016-2035)	1.13	-0.41	0.72	-0.59	0.54
2017 SUFG Base (2016-2035)	1.13	-0.46	0.67	-0.65	0.48

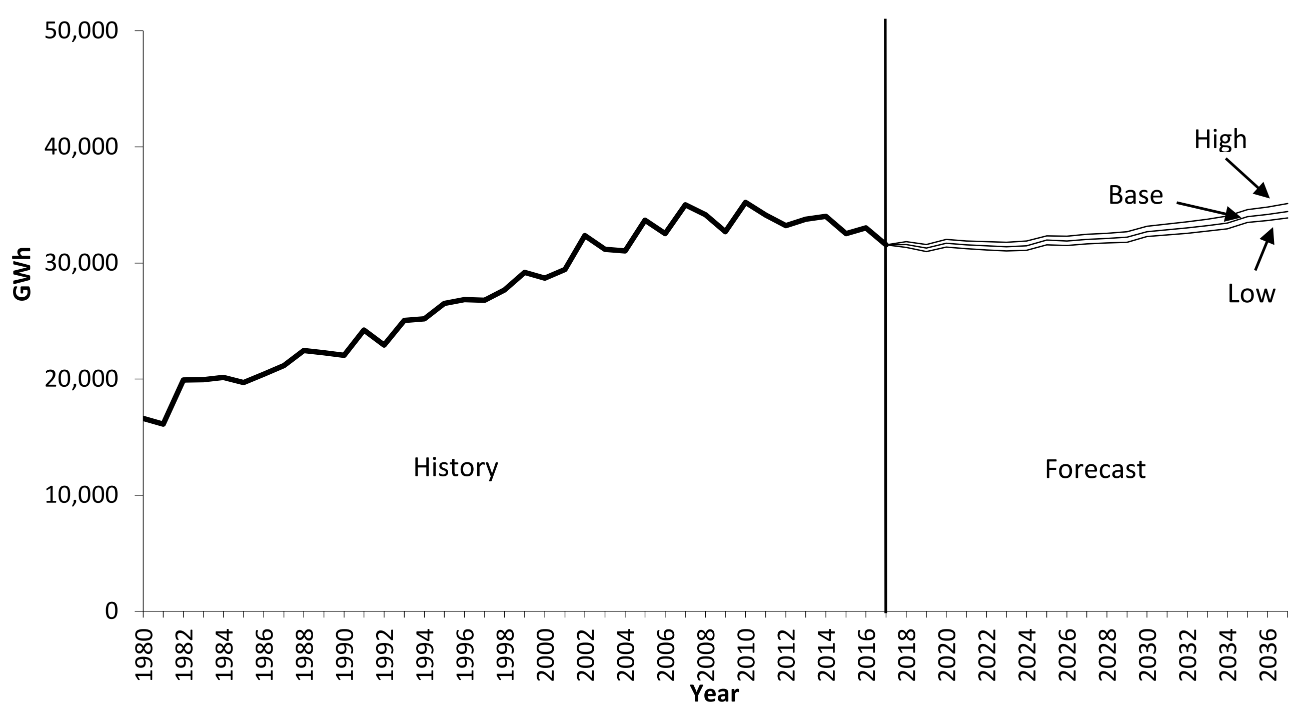
Table 5-4. Residential Model - Growth Rates (Percent) for Selected Variables (2019 SUFG Scenarios and 2018 and 2017 Base Forecasts)

Forecast	Current Scenarios (2018-2037)			2018 Forecast (2016-2035)	2017 Forecast (2016-2035)
	Base	Low	High	Base	Base
No. of Customers	1.087	1.075	1.092	1.127	1.131
Electric Rates	0.61	0.80	0.35	0.69	1.20

Table 5-5. Indiana Residential Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2018-2037	0.45	0.41	0.51

Figure 5-4. Indiana Residential Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5, with growth rates provided in Table 5-6. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise until 2026 before gradually decreasing afterwards. SUFG's real price projections for most of the individual IOUs follow similar patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2017 Dollars)

Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	3.96
1985-1990	-3.98
1990-1995	-2.80
1995-2000	-0.99
2000-2005	-0.72
2005-2017	2.23
2018-2037	0.92

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 6

Commercial Electricity Sales

Overview

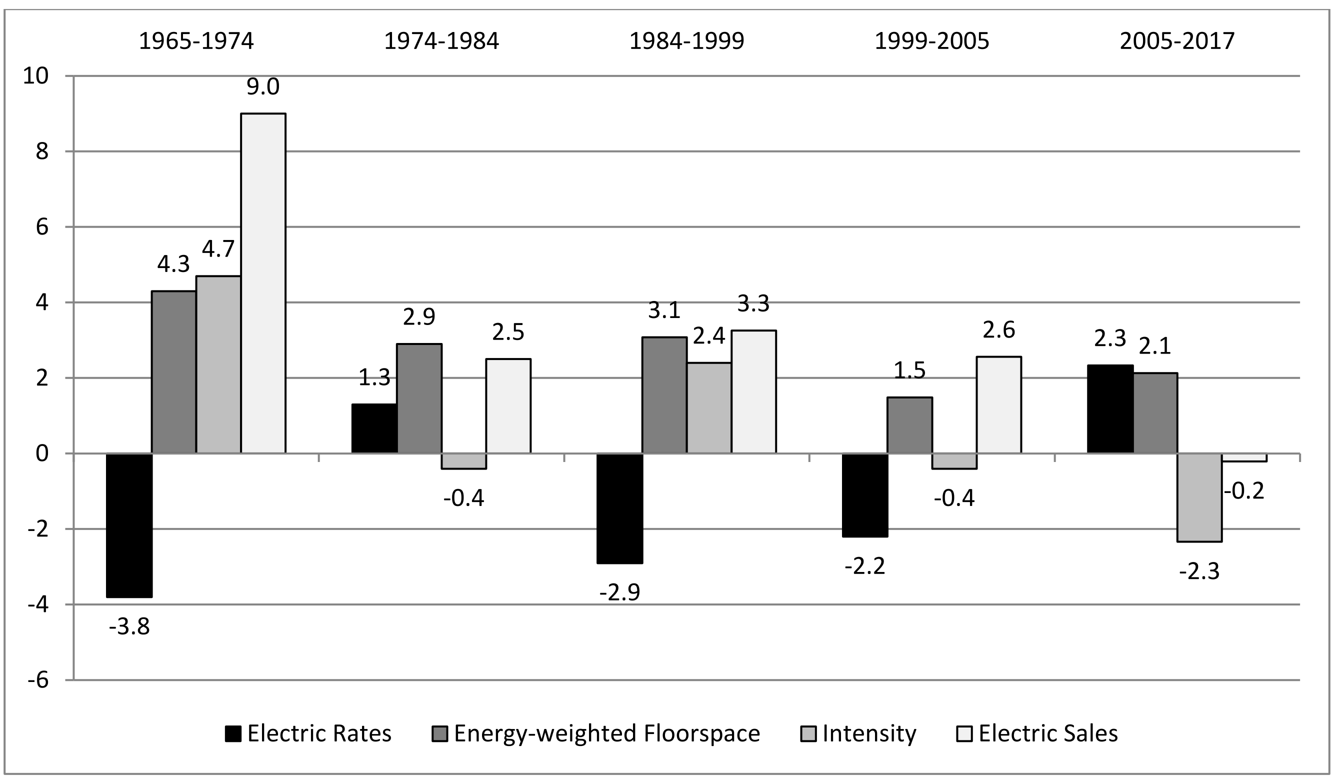
SUFG has two distinct models of commercial electricity sales, econometric and end-use. Both have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy. CEDMS, however, bears little resemblance to its ORNL ancestor. Like the residential sector end-use model REDMS, Jerry Jackson Associates actively supports CEDMS, and it continues to define the state-of-the-art in commercial sector end-use forecasting models.

For a few years in the mid-1990s, SUFG relied on its own econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type. SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model. SUFG then made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over several years, SUFG is confident it provides realistic energy projections under a wide range of assumptions. Second, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial end-use and econometric models are small, since both models forecast similar changes in electric intensity. SUFG used a version of CEDMS for this set of projections.

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different in each of five recent periods (see Figure 6-1).

Figure 6-1. State Historical Trends in the Commercial Sector (Annual Percent Change)



Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per year) as seen in Figure 6-1 prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during 1974-1984, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-1999 period, electric intensity rose but at a slower rate (2.4 percent) than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average, but these efficiency improvements are offset by an increased demand for energy services.

Over the 1999-2005 timeframe, a decrease in economic activity retarded growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. Recently the recession coupled with increasing real electricity prices has accelerated these trends, with the notable exception of the stock of commercial floor space. For 2005-2017 real electricity prices have risen, commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline, and commercial sector electricity use stagnating.

Model Description

Figure 6-2 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the commercial sector as it is for modeling the residential sector. CEDMS categorizes commercial buildings into 21 building types. It also divides energy use in each building type among 9 possible end uses, including a residual use category (labeled "other"). For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-2.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

CEDMS projects energy use for each building vintage according to the following equation:

$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, building type l and vintage t in the forecast year;

t = building vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/sqft/year or Btu/sqft/year;

a = fraction of floor space served by fuel i, end use k, and building type l for floor space additions of vintage t;

A = floor space additions by vintage t and building type l; and

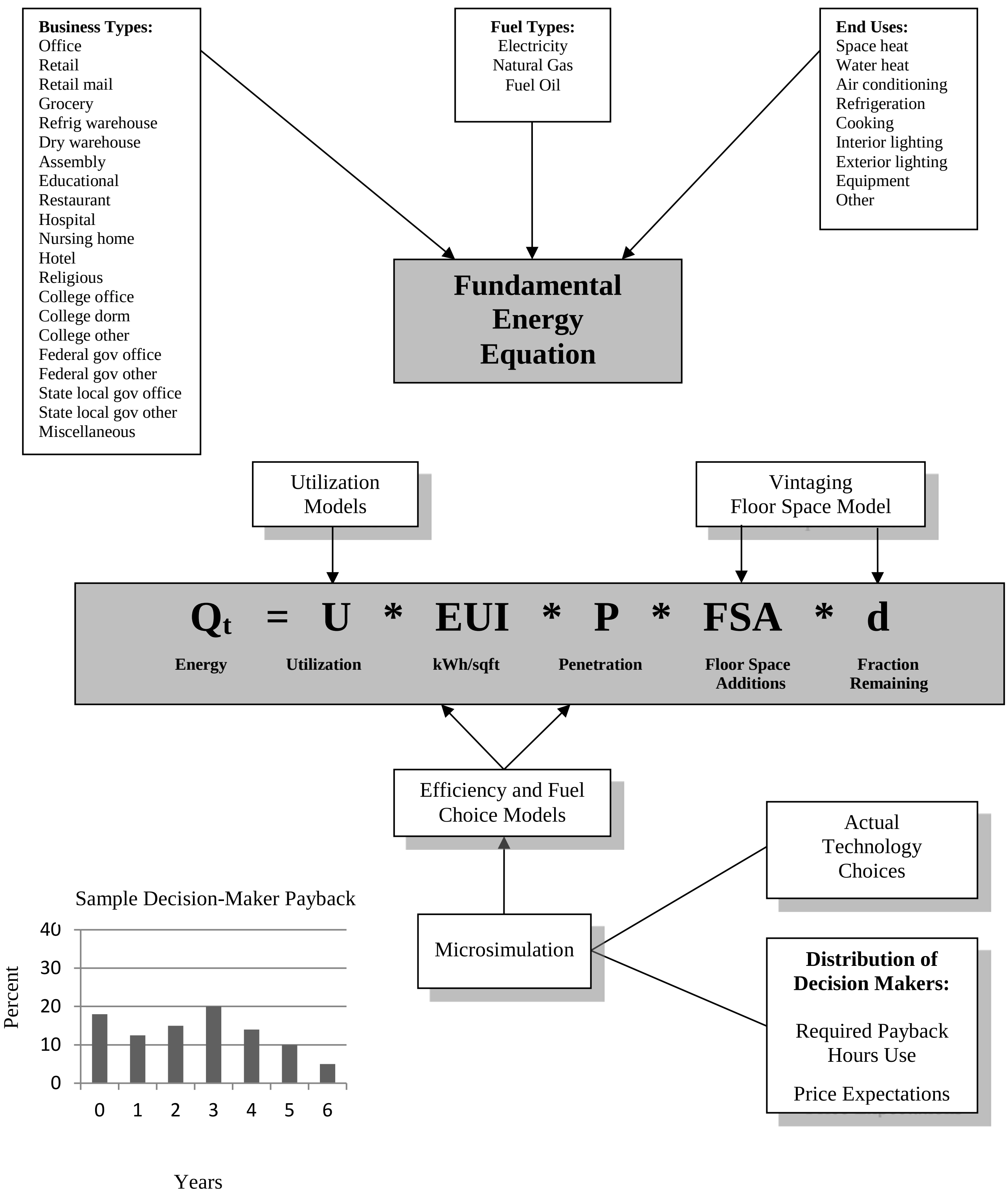
d = fraction of floor space of vintage t still standing in forecast year T.

CEDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

CEDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample firms in the model make choices from a set of discrete heating, ventilation and air conditioning (HVAC) equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration and lighting. HVAC and lighting account for about 80 percent of total electricity use by commercial firms.

Equipment standards are easily incorporated in CEDMS' equipment choice sub-models. In addition to efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

Figure 6-2. Structure of Commercial End-Use Energy Modeling System



For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary of Results

The remainder of this chapter describes SUFG's commercial electricity sales projections. First, the current base projection of commercial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population) and electricity prices. The sensitivity of the electricity sales projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-1. An interesting result is that changes in commercial floor space lead to more than proportional changes in electricity use. The reason for this is that new buildings tend to have greater saturations of electric end uses, which more than offsets the greater efficiency of those end uses.

Table 6-1. Commercial Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Floor space	10.5
Electric Rates	-2.6

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. As can be seen, the current base projection of Indiana commercial electricity sales growth declines annually by 0.10 percent, as decreases in the first half of the forecast offset increases in the second half. As shown in Figure 6-3, the current projection lies well below the 2017 forecast and 2018 forecast update. The current projection lies below the old projections for the whole forecast period.

Floor space growth is offset by decreases in utilization. Utilization, the amount of electricity used per unit of floor space, decreases because of increasing electricity prices, low natural gas prices and the implementation of new efficiency standards. Incremental DSM programs also have a significant effect on electricity sales.

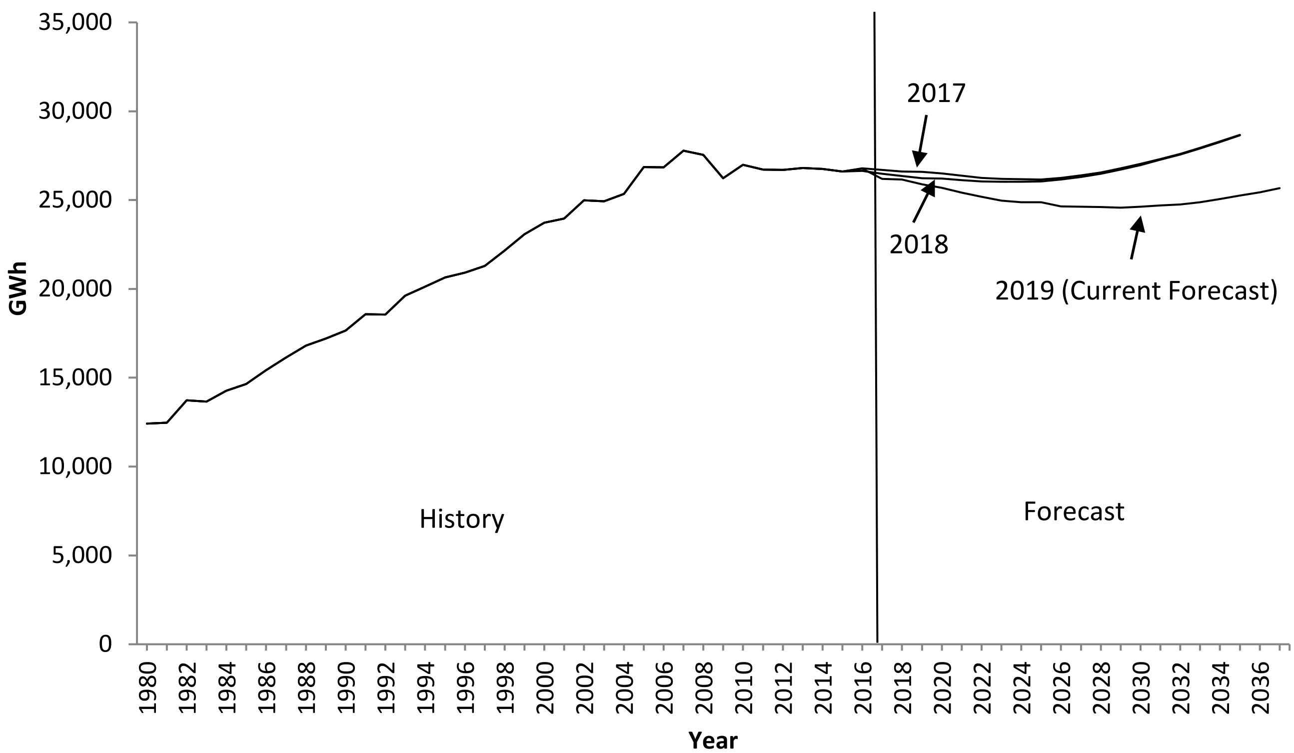
The growth rates for the major explanatory variables are shown in Table 6-3. Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG projections. The historical and 2019 forecast values are provided in the Appendix of this report.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.12 percent lower and 0.14 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

Table 6-2. Indiana Commercial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	-0.10	2018-2037
2018	0.38	2016-2035
2017	0.36	2016-2035

Figure 6-3. Indiana Commercial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 6-3. Commercial Model - Growth Rates (Percent) for Selected Variables (2019 SUFG Scenarios and 2018 and 2017 Base Forecasts)

Forecast	Current Scenarios (2018-2037)			2018 Forecast (2016-2035)	2017 Forecast (2016-2035)
	Base	Low	High	Base	Base
Electric Rates	0.61	0.80	0.35	0.98	1.40
Natural Gas Price	1.44	1.44	1.44	1.61	2.58
Energy-weighted Floor Space	0.78	0.70	0.85	0.80	0.76

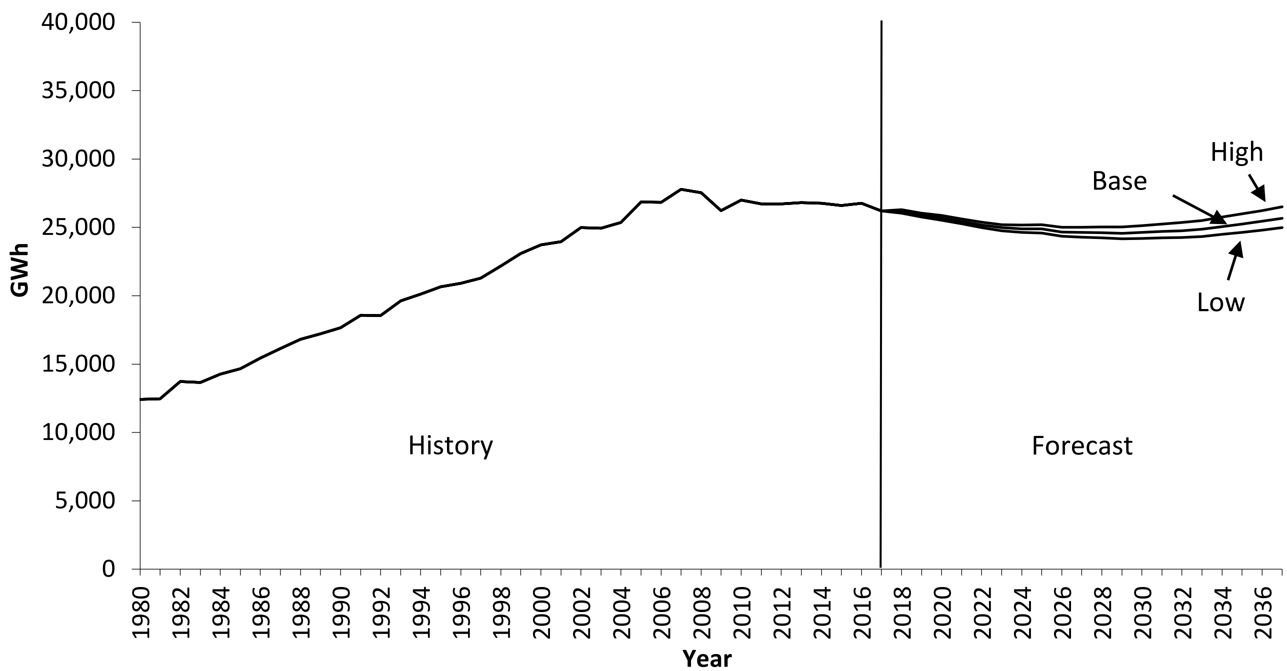
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2019 SUFG Base (2018-2037)	0.78	-0.44	0.34	-0.88	-0.10
2018 SUFG Base (2016-2035)	0.80	-0.06	0.74	-0.42	0.38
2017 SUFG Base (2016-2035)	0.76	-0.04	0.72	-0.40	0.36

Table 6-5. Indiana Commercial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2018-2037	-0.10	-0.22	0.04

Figure 6-4. Indiana Commercial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-5, with growth rates provided in Table 6-6. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real commercial electricity prices to reach their peak level in 2026 and gradually decline afterwards. SUFG's real price projections for most of the individual IOUs follow similar pattern as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2017 Dollars)

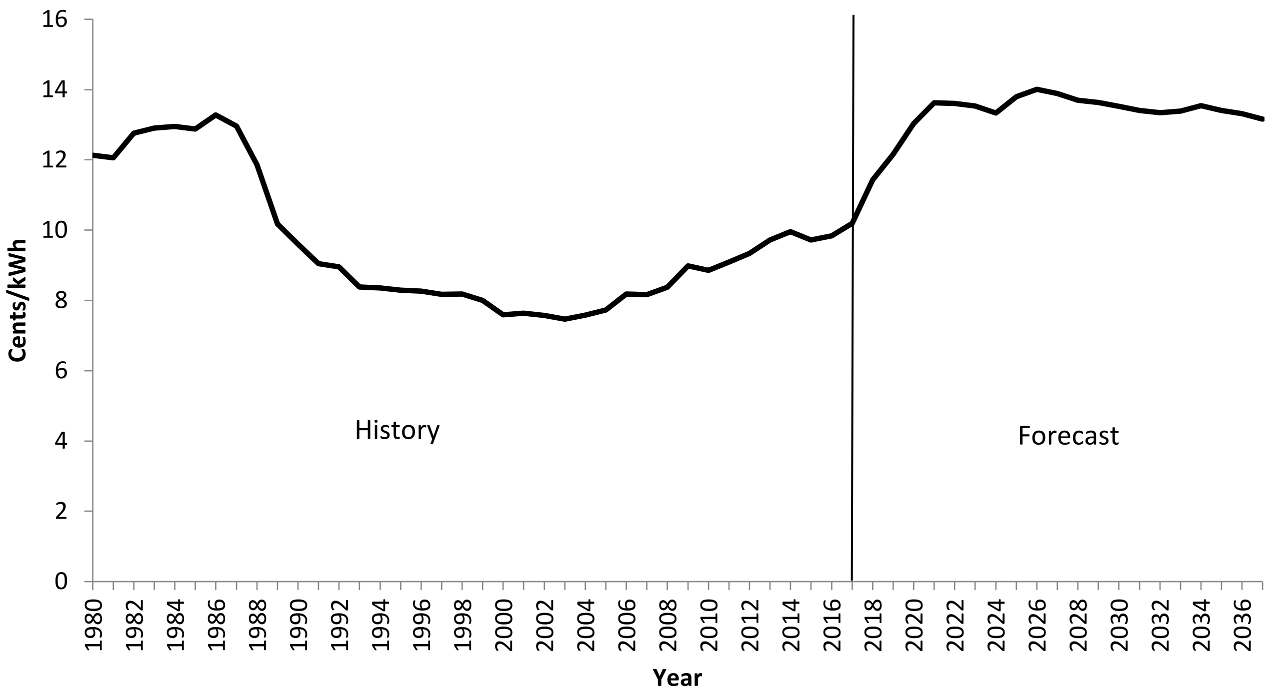


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.19
1985-1990	-5.69
1990-1995	-2.90
1995-2000	-1.75
2000-2005	0.36
2005-2017	2.34
2018-2037	0.74

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 7

Industrial Electricity Sales

Overview

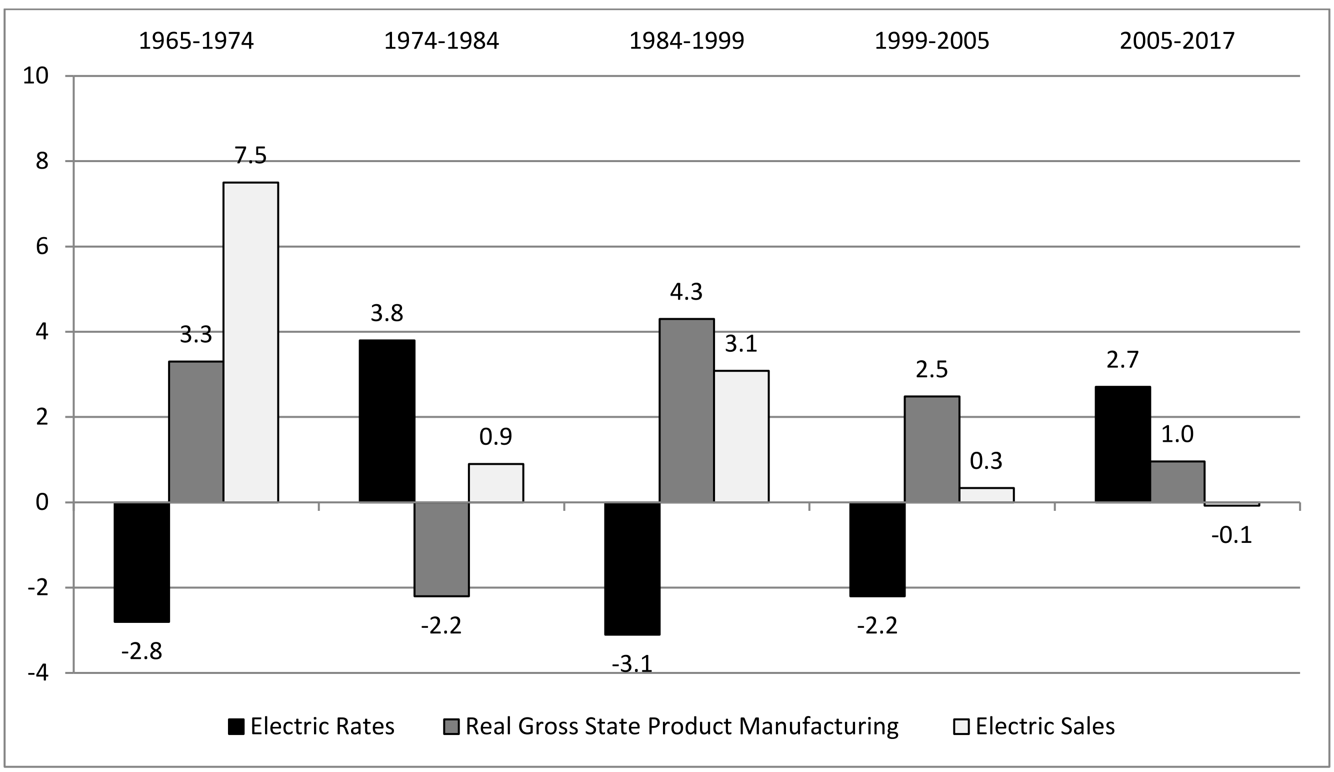
SUFG has used several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state. Additionally, SUFG has used in various forecasts a highly detailed process model of the iron and steel industry, scenario-based models of the aluminum and foundries components of the primary metals industry, and an industrial motor drive model to evaluate and forecast the effect of motor technologies and standards.

The econometric model is calibrated at the statewide level of electricity purchases from data on cost shares obtained from the U.S. Department of Commerce Annual Survey of Manufacturers. SUFG has been using INDEED since 1992 to project electricity sales for the 15 individual industries within each of the five IOU service areas. There are many econometric formulations that can be used to forecast industrial electricity use, which range from single equation factor demand models and fuel share models to "KLEM" models (KLEM denotes capital, labor, energy and materials). INDEED is a KLEM model. A KLEM model is based on the assumption that firms act as though they are minimizing costs to produce given levels of output. Thus, a KLEM model projects the changes in the quantity of each input, which result from changes in input prices and levels of output under the cost minimization assumption. For each of the 15 industry groups, INDEED projects the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal and materials.

Historical Perspective

SUFG distinguishes five recent periods of distinctly different economic activity and growth - 1965-1974, 1974-1984, 1984-1999, 1999-2005, and the more recent period 2005-2017. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the five periods.

Figure 7-1. State Historical Trends in the Industrial Sector (Annual Percent Change)



During the decade prior to the OPEC oil embargo, industrial electricity sales increased 7.5 percent annually. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices (2.8 percent per year in real terms) and growing manufacturing output (3.3 percent per year). During the decade following 1974, sales growth slowed as real electricity prices increased at an average rate of 3.8 percent per year and the state's manufacturing output declined at a rate of 2.2 percent per year. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales from 7.5 percent per year during 1965-1974 to 0.9 percent per year in the decade that followed. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" of 1974-1984. The ensuing period, 1984-1999, experienced another dramatic turnaround. The growth rate of industrial output once again became positive, and was substantially above the rate observed 1965-1974. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 3.1 percent per year during these 15 years.

The effect of the economic slowdown from 1999-2005 is particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Since 2005 real industrial electricity prices have increased, real growth in manufacturing output has continued to be modest, and overall growth in industrial electricity has remained stagnant.

Model Description

SUFG's primary industrial-sector forecasting model, INDEED, consists of a set of econometric models for each of Indiana's major industries listed in Table 7-1. The general structure of the models is illustrated in Figure 7-2.

Each model is driven by projections of GSP for selected industries over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Seventy percent of state GSP is accounted for by the following industries: primary metals, 12 percent; fabricated metals, 5 percent; industrial machinery and equipment, 7 percent; chemicals, 12 percent; transportation equipment, 29 percent; and electronic and electric equipment, 5 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemicals and primary metals industries are very electric-intensive industries. Combined, they account for 50% of total state industrial electricity use. Column four gives the current base output projections for the major industries obtained from the most recent CEMR forecast (after the adjustment to the transportation equipment industry discussed in Chapter 4). As explained in Chapter 4, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying sector employment projections by a projection of GSP per employee, a measure of labor productivity.

This is the eighth SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG is still using the SIC system, SUFG maps industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process was relatively straightforward with the exception of SIC 28, chemical manufacturing. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the manufacturing sector as a whole. This was necessary because CEMR's projections did not specifically include chemicals manufacturing, a large purchaser of electricity in Indiana.

Each industrial sector econometric model forecasts the total cost of producing the given output and the cost shares for each major input, i.e., capital, labor, electricity, gas, oil, coal and materials. The quantity of electricity is determined given the expenditure of electricity for each industry and its price.

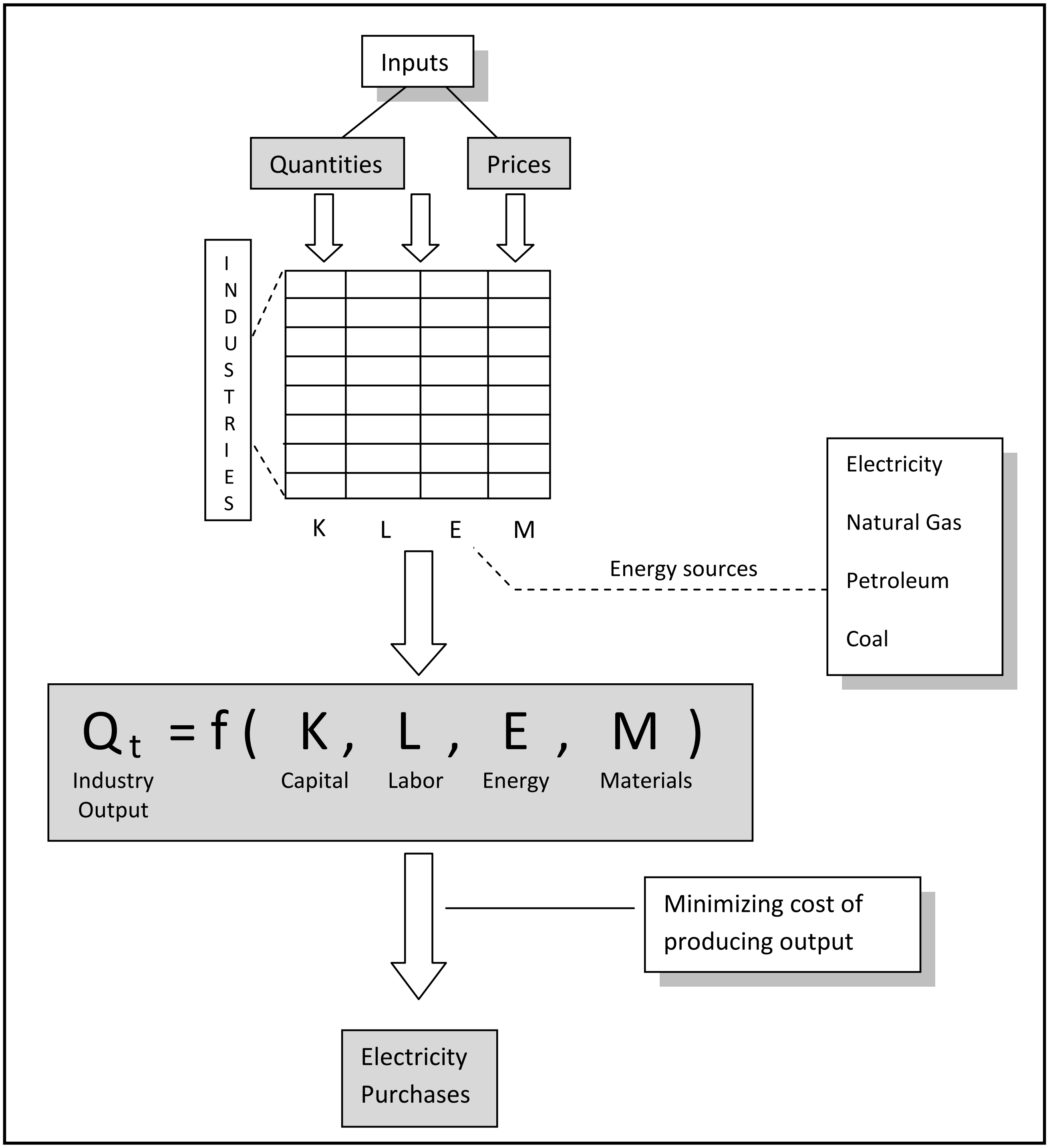
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimizes the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices, SUFG uses the current EIA forecast, which assumes that real natural gas prices, which dropped from 2008 to 2012 before slightly rising in 2014 and then dropping again in 2015, will gradually rise over the forecast horizon. Distillate prices also decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded significantly through 2012-2013 before declining again in 2014, followed by substantial decreases in 2015 and 2016. They are projected to rebound quickly in 2017 and 2018 before gradually decreasing again through 2019-2024 and then growing at a slower pace over the remainder of the forecast horizon. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 1.26 percent per year, without DSM, over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Without DSM) (Percent)

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	3.60	6.18	0.65	1.39	0.10	1.48
24	Lumber & Wood Products	2.00	0.66	0.12	1.39	-0.99	0.40
25	Furniture & Fixtures	2.84	0.37	0.05	1.83	-0.47	1.36
26	Paper & Allied Products	1.39	3.30	0.90	1.39	-0.27	1.12
27	Printing & Publishing	2.62	1.00	0.15	1.39	-0.31	1.08
28	Chemicals & Allied Products	12.48	20.15	0.61	1.39	-0.17	1.21
30	Rubber & Misc. Plastic Products	3.82	5.82	0.58	1.72	-0.63	1.10
32	Stone, Clay, & Glass Products	2.88	5.25	0.69	1.83	-0.44	1.39
33	Primary Metal Products	11.68	30.00	0.97	-2.12	2.69	0.56
34	Fabricated Metal Products	5.42	6.11	0.43	2.13	-0.47	1.67
35	Industrial Machinery & Equipment	7.03	4.20	0.23	1.46	0.40	1.87
36	Electronic & Electric Equipment	4.66	2.10	0.17	-0.56	-0.11	-0.68
37	Transportation Equipment	29.45	7.33	0.09	2.02	-0.07	1.95
38	Instruments & Related Products	3.87	0.98	0.10	1.83	-0.80	1.02
39	Miscellaneous Manufacturing	2.09	0.96	0.17	1.83	-1.84	-0.01
Total	Manufacturing	100.00	100.00	0.38	1.35	-0.09	1.26

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's industrial electricity sales projections. First, the current base projection of industrial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industrial electricity consumption in the econometric model. Electricity sales (GWh) are most sensitive to changes in output and electric rates, somewhat sensitive to changes in gas and oil prices, and insensitive to changes in assumed coal prices. Other major variables affecting industrial electricity use include the prices of materials, capital and labor. The model's sensitivities were determined by increasing each variable ten percent above the base scenario levels and observing the percent change in forecast industrial electricity use after 10 years.

Table 7-2. Industrial Model Long-Run Sensitivities

A 10 Percent Increase In	Causes This Percent Change in Electric Sales
Real Manufacturing Product	10.0
Electric Rates	-4.8
Natural Gas Price	1.4
Oil Prices	0.9
Coal Prices	0.2

Indiana Industrial Electricity Sales Projections

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-3. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2017, 2018, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Industrial sector DSM programs are expected to have negligible impact on retail sales, due in part to industrial customers having the ability to opt out. The effect of earlier conservation activities are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2017 level of approximately 39,300 GWh to about 50,200 GWh by 2037. This growth rate of 1.26 percent per year is substantially higher than both the -0.10 percent rate projected for the commercial sector and the 0.45 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast shows little change through 2023, then increases through the remainder of the forecast horizon.

As compared to the previous forecasts, the growth in industrial electricity sales is impacted by two counterbalancing factors: manufacturing output and electricity intensity (electricity usage per dollar of output). The increase in intensity occurs because a tightening of the labor market makes electricity more competitive as a factor of production in the INDEED model. An example of this would be increased automation in the production process that allows for less labor but uses more energy. Industrial electricity sales are projected to be lower in the 2019 forecast because the reduction in the growth of manufacturing output is larger than the increase in intensity.

Table 7-5 and Figure 7-4 show how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 57,360 GWh by 2037, 14.2 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 45,021 GWh sales by 2037, 10.4 percent below the base scenario.

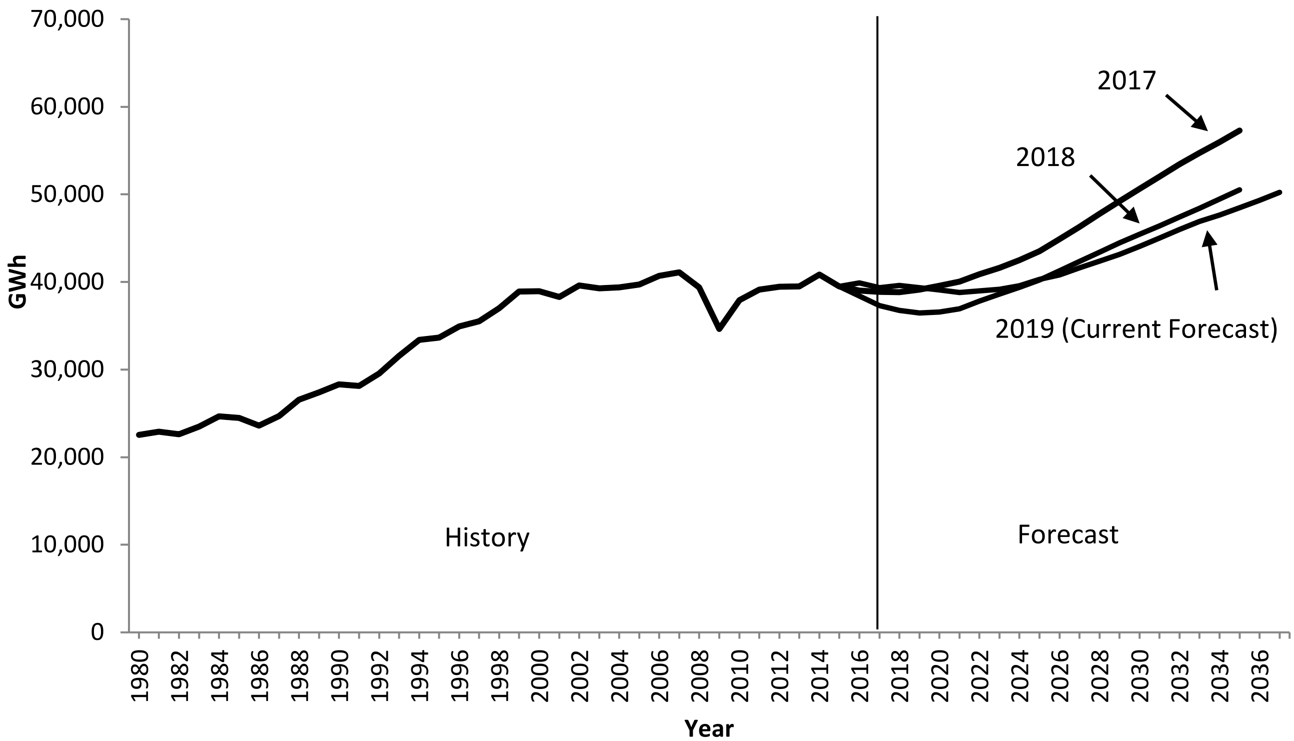
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 1.35 percent per year during the forecast period. That rate is 2.04 percent in the high scenario and 0.66 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

The high and low scenarios reflect optimistic and pessimistic views, respectively, regarding the ability of Indiana's industries to compete with producers from other states.

Table 7-3. Indiana Industrial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2019	1.26	2018-2037
2018	1.45	2016-2035
2017	2.04	2016-2035

Figure 7-3. Indiana Industrial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

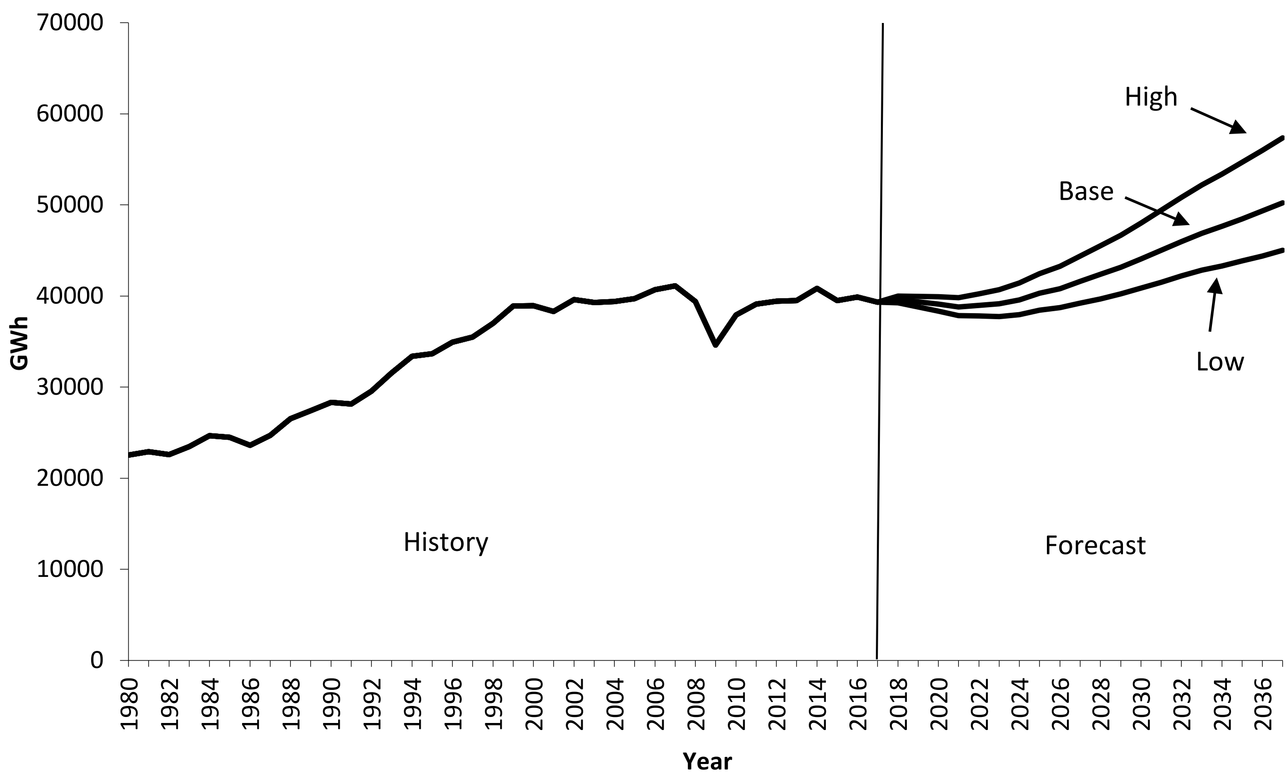
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2019 SUFG Base (2018-2037)	1.35	-0.71	0.64	0.62	1.26	0.62	1.26
2018 SUFG Base (2016-2035)	2.18	-0.58	1.60	-0.13	1.47	-0.15	1.45
2017 SUFG Base (2016-2035)	2.40	-0.29	2.11	-0.06	2.05	-0.07	2.04

Table 7-5. Indiana Industrial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2018-2037	1.26	0.72	1.92

Figure 7-4. Indiana Industrial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-5. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise until 2026 and then decline gradually. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-5. Indiana Industrial Base Real Price Projections (Cents/kWh in 2017 Dollars)

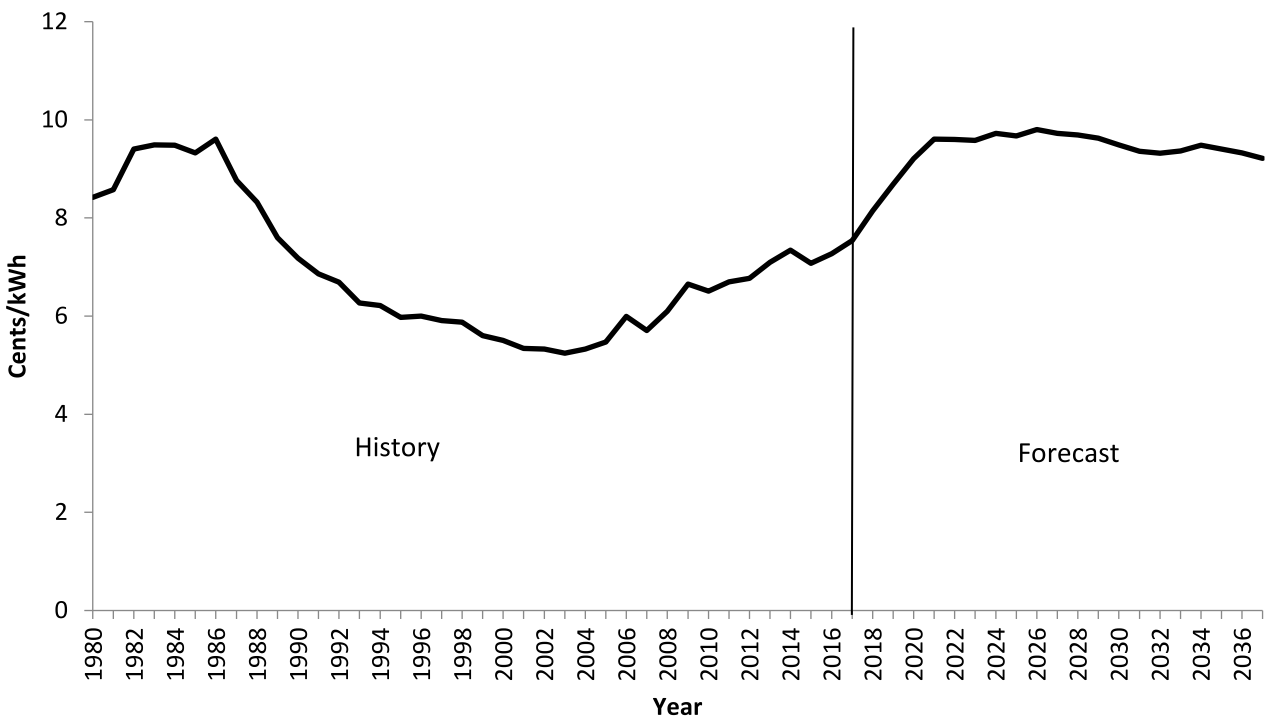


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.08
1985-1990	-5.10
1990-1995	-3.61
1995-2000	-1.63
2000-2005	-0.12
2005-2017	2.71
2018-2037	0.65

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Appendix

In developing the historical energy, summer peak demand and rates data shown in the body and appendix of this document, SUFG relied on several sources of data. These sources include:

1. FERC Form 1;
2. Rural Utilities Service (RUS) Form 7 or Form 12;
3. Uniform Statistical Report;
4. Utility Load Forecast Reports;
5. Integrated Resource Plan Filings;
6. Annual Reports; and
7. SUFG Confidential Data Requests.

SUFG relied on public sources where possible, but some generally more detailed data was obtained from Indiana utilities under confidential agreements of nondisclosure. All data presented in this report have been aggregated to total Indiana statewide energy, demand and rates to avoid disclosure.

In most instances the source of SUFG's data can be traced to a particular page of a certain publication, e.g., residential energy sales for an IOU are found on page 304 of FERC Form 1. However, in several cases it is not possible to directly trace a particular number to a public data source. These exceptions arise due to:

1. geographic area served by the utility;
2. classification of sales data; and
3. unavailability of sectoral level sales data.

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. I&M's load is split approximately 86-14 percent between Indiana and Michigan. While the majority of WVPA's load is in Indiana, 68 percent, it does have members in Illinois and Missouri. IMPA has a wholesale member in Ohio although approximately 99 percent of their load is still in Indiana. Hoosier Energy serves members in Indiana and Illinois. Approximately 95 percent of Hoosier's load is currently in Indiana. These utilities have provided SUFG with data pertaining to their Indiana load.

Some Indiana utilities report sales to the commercial and industrial sectors (SUFG's classification) as sales to one aggregate classification or sales to small and large customers. In order to obtain commercial and industrial sales for these utilities, SUFG has requested data in these classifications directly from the utilities, developed approximation schemes to disaggregate the sales data, or combined more than one source of data to develop commercial and industrial sales estimates. For example, until recently the Uniform Statistical Report contained industrial sector sales for IOUs. This data can be subtracted from aggregate FERC Form 1 small and large customer sales data to obtain an estimate of commercial sales.

SUFG does not have sectoral level sales data for the unaffiliated rural electric membership cooperatives (REMCs) and unaffiliated municipalities. SUFG obtains aggregate sales data from the FERC Form 1, then allocates the sales to residential, commercial, industrial and other sales with an allowance for losses. These allocation factors were developed by examining the mix of energy sales for other Indiana REMCs and municipalities. Thus, the sales estimates for unaffiliated REMCs are weighted heavily toward the residential sector and those for unaffiliated municipalities are more evenly balanced between the residential, commercial and industrial sectors.

SUFG's estimates of losses are calculated using a constant percentage loss factor applied to retail sales and sales-for-resale (when appropriate). These loss factors are based on FERC Form 1 data and discussions with Indiana utility personnel.

Total energy requirements for an individual utility are obtained by adding retail sales, sales-for-resale (if any) and losses. Total energy requirements for the state as a whole are obtained by adding retail sales and losses for the eight entities that SUFG models. Sales-for-resale are excluded from the state aggregate total energy requirements to avoid double counting.

Summer peak demand estimates are based on FERC Form 1 data for the IOUs with the exception of I&M, which provided SUFG with peak demand for their Indiana jurisdiction, and company sources for Hoosier Energy, IMPA and WVPA.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity. Diversity refers to the fact that all Indiana utilities do not experience their summer peak demand at the same instant. Due to differences in weather, sectoral mix, end-use saturation, etc., the utilities tend to face their individual summer peak demands at different hours, days, or even months. To obtain an estimate of statewide peak demand, the summer peak demand estimates for the individual utilities are added together and adjusted for diversity.

The historical energy sales and peak demand data presented in this appendix represent SUFG's accounting of actual historical values. In developing the current forecast, SUFG was required to estimate some detailed sector-specific data for a few utilities. This data was unavailable from some utilities due to changes in data collection and/or reporting requirements. In the industrial sector, SUFG estimates two-digit, Standard Industrial Code sales and revenue data for two IOUs. This data was estimated from total industrial sales data by assuming the same allocation of industrial sales at the two-digit level as observed during recent years. SUFG was also unable to obtain sales and revenue data for the commercial sector at the same level of detail from some IOUs. The detailed commercial sector data is necessary to calibrate SUFG's commercial sector model, but since the commercial sector model was not recalibrated for this forecast, no estimation was attempted. The not-for-profit utilities have not traditionally been able to supply SUFG with data at the two-digit level of detail. However, the not-for-profit utilities were able to provide SUFG with a breakdown of member load by customer class.

SUFG feels relatively comfortable with these estimates, but is concerned about the future availability of detailed sector-specific data. If data proves to be unavailable in the future, SUFG will either be forced to develop more sophisticated allocation schemes to support the energy forecasting models or develop less data intensive, less detailed energy forecasting models.

SUFG 2019 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,729
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	21,048
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,423
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Hist	2016	33,024	26,763	39,876	603	100,265	7,019	107,284	19,587
Hist	2017	31,565	26,198	39,342	600	97,705	6,839	104,544	18,722
Frcst	2018	31,592	26,164	39,611	609	97,976	7,415	105,391	19,444
Frcst	2019	31,288	25,893	39,363	610	97,154	7,360	104,514	19,314
Frcst	2020	31,694	25,686	39,098	612	97,090	7,371	104,461	19,326
Frcst	2021	31,558	25,425	38,783	616	96,382	7,345	103,728	19,184
Frcst	2022	31,475	25,180	38,963	621	96,239	7,353	103,592	19,138
Frcst	2023	31,405	24,975	39,155	624	96,158	7,368	103,527	19,105
Frcst	2024	31,480	24,886	39,576	627	96,569	7,421	103,990	19,169
Frcst	2025	31,966	24,881	40,303	634	97,785	7,547	105,333	19,376
Frcst	2026	31,897	24,648	40,813	636	97,994	7,560	105,555	19,417
Frcst	2027	32,039	24,631	41,593	640	98,904	7,644	106,548	19,572
Frcst	2028	32,107	24,601	42,366	643	99,718	7,718	107,435	19,711
Frcst	2029	32,212	24,571	43,143	646	100,572	7,793	108,365	19,862
Frcst	2030	32,694	24,622	44,074	650	102,041	7,912	109,953	20,139
Frcst	2031	32,844	24,692	45,012	653	103,200	8,005	111,205	20,346
Frcst	2032	33,010	24,760	45,981	655	104,406	8,102	112,508	20,562
Frcst	2033	33,211	24,871	46,899	658	105,639	8,204	113,844	20,787
Frcst	2034	33,441	25,058	47,651	661	106,810	8,294	115,104	20,997
Frcst	2035	33,977	25,248	48,475	663	108,364	8,409	116,773	21,296
Frcst	2036	34,169	25,443	49,328	664	109,604	8,500	118,104	21,521
Frcst	2037	34,419	25,669	50,229	666	110,983	8,602	119,585	21,781
Average Compound Growth Rates (%)									
Year-Year		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995		3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000		1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005		3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010		0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015		-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020		-0.52	-0.70	-0.20	0.53	-0.43	1.19	-0.32	-0.21
2020-2025		0.17	-0.63	0.61	0.70	0.14	0.47	0.17	0.05
2025-2030		0.45	-0.21	1.80	0.49	0.86	0.95	0.86	0.78
2030-2037		0.74	0.60	1.89	0.34	1.21	1.20	1.21	1.13
2018-2037		0.45	-0.10	1.26	0.47	0.66	0.78	0.67	0.60

SUFG 2019 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,729
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	21,048
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,423
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Hist	2016	33,024	26,763	39,876	603	100,265	7,019	107,284	19,587
Hist	2017	31,565	26,198	39,342	600	97,705	6,839	104,544	18,722
Frcst	2018	31,327	26,044	39,268	605	97,244	7,343	104,588	19,440
Frcst	2019	30,992	25,745	38,814	605	96,156	7,267	103,423	19,263
Frcst	2020	31,368	25,532	38,350	608	95,858	7,260	103,118	19,235
Frcst	2021	31,220	25,261	37,853	611	94,945	7,220	102,165	19,058
Frcst	2022	31,117	24,992	37,808	615	94,532	7,208	101,740	18,968
Frcst	2023	31,040	24,753	37,754	618	94,165	7,204	101,368	18,885
Frcst	2024	31,089	24,624	37,939	622	94,273	7,234	101,507	18,899
Frcst	2025	31,572	24,597	38,450	629	95,248	7,344	102,592	19,067
Frcst	2026	31,513	24,352	38,728	631	95,224	7,343	102,567	19,068
Frcst	2027	31,630	24,293	39,210	635	95,768	7,400	103,168	19,162
Frcst	2028	31,712	24,234	39,688	639	96,272	7,452	103,725	19,247
Frcst	2029	31,786	24,159	40,223	641	96,809	7,504	104,313	19,342
Frcst	2030	32,266	24,192	40,857	645	97,960	7,602	105,561	19,564
Frcst	2031	32,406	24,227	41,506	648	98,787	7,671	106,457	19,716
Frcst	2032	32,558	24,259	42,196	650	99,664	7,744	107,408	19,873
Frcst	2033	32,738	24,335	42,827	653	100,552	7,820	108,373	20,036
Frcst	2034	32,950	24,483	43,304	655	101,393	7,888	109,281	20,191
Frcst	2035	33,486	24,642	43,845	658	102,631	7,981	110,612	20,433
Frcst	2036	33,652	24,795	44,402	659	103,507	8,045	111,552	20,595
Frcst	2037	33,886	24,980	45,021	661	104,548	8,124	112,672	20,793

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015	-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020	-0.73	-0.82	-0.58	0.37	-0.69	0.89	-0.58	-0.31
2020-2025	0.13	-0.74	0.05	0.69	-0.13	0.23	-0.10	-0.17
2025-2030	0.44	-0.33	1.22	0.52	0.56	0.69	0.57	0.52
2030-2037	0.70	0.46	1.40	0.34	0.93	0.95	0.94	0.87
2018-2037	0.41	-0.22	0.72	0.47	0.38	0.53	0.39	0.35

SUFG 2019 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,729
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	21,048
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,423
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Hist	2016	33,024	26,763	39,876	603	100,265	7,019	107,284	19,587
Hist	2017	31,565	26,198	39,342	600	97,705	6,839	104,544	18,722
Frcst	2018	31,846	26,289	39,997	613	98,746	7,489	106,234	19,449
Frcst	2019	31,587	26,043	39,967	614	98,212	7,457	105,669	19,368
Frcst	2020	32,019	25,862	39,915	617	98,414	7,487	105,901	19,425
Frcst	2021	31,900	25,615	39,825	622	97,961	7,481	105,442	19,325
Frcst	2022	31,828	25,376	40,251	626	98,081	7,507	105,589	19,325
Frcst	2023	31,777	25,204	40,689	629	98,299	7,543	105,842	19,344
Frcst	2024	31,883	25,172	41,430	633	99,118	7,626	106,744	19,477
Frcst	2025	32,345	25,194	42,449	639	100,627	7,769	108,396	19,731
Frcst	2026	32,299	25,002	43,254	641	101,196	7,807	109,003	19,838
Frcst	2027	32,456	25,008	44,370	646	102,480	7,916	110,396	20,055
Frcst	2028	32,550	25,025	45,494	648	103,718	8,019	111,737	20,270
Frcst	2029	32,685	25,035	46,688	652	105,060	8,128	113,188	20,505
Frcst	2030	33,163	25,124	48,019	655	106,962	8,276	115,238	20,854
Frcst	2031	33,338	25,236	49,399	658	108,631	8,403	117,033	21,150
Frcst	2032	33,543	25,349	50,817	660	110,369	8,537	118,906	21,459
Frcst	2033	33,772	25,509	52,196	663	112,140	8,674	120,814	21,775
Frcst	2034	34,043	25,747	53,391	666	113,846	8,801	122,647	22,081
Frcst	2035	34,599	25,992	54,675	668	115,935	8,953	124,888	22,471
Frcst	2036	34,819	26,232	55,994	669	117,714	9,080	126,794	22,792
Frcst	2037	35,108	26,511	57,360	671	119,650	9,221	128,871	23,146

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015	-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020	-0.32	-0.57	0.22	0.69	-0.16	1.57	-0.05	-0.21
2020-2025	0.20	-0.52	1.24	0.70	0.45	1.07	0.47	0.75
2025-2030	0.50	-0.06	2.50	0.49	1.23	1.52	1.23	1.36
2030-2037	0.82	0.77	2.57	0.34	1.61	1.56	1.61	1.50
2018-2037	0.51	0.04	1.92	0.47	1.02	1.10	1.02	0.92

Indiana Base Average Retail Rates (Cents/kWh) (in 2017 Dollars)

Year	Res	Com	Ind	Average
1990	11.35	9.60	7.18	9.02
1991	10.68	9.05	6.86	8.61
1992	10.62	8.96	6.69	8.42
1993	9.99	8.39	6.27	7.91
1994	10.01	8.36	6.22	7.85
1995	9.85	8.29	5.98	7.72
1996	9.82	8.26	6.00	7.69
1997	10.02	8.17	5.91	7.66
1998	10.06	8.18	5.88	7.66
1999	9.77	8.00	5.60	7.41
2000	9.37	7.59	5.50	7.13
2001	9.18	7.63	5.34	7.05
2002	9.00	7.57	5.33	7.01
2003	8.97	7.47	5.24	6.93
2004	9.02	7.59	5.33	7.02
2005	9.04	7.73	5.47	7.18
2006	9.69	8.18	6.00	7.67
2007	9.31	8.16	5.70	7.48
2008	9.68	8.37	6.09	7.83
2009	10.29	8.98	6.65	8.49
2010	10.08	8.86	6.51	8.31
2011	10.45	9.10	6.70	8.52
2012	10.73	9.34	6.77	8.68
2013	11.20	9.72	7.10	9.08
2014	11.51	9.95	7.34	9.34
2015	11.47	9.72	7.07	9.15
2016	11.45	9.84	7.27	9.26
2017	11.78	10.19	7.54	9.54
2018	13.20	11.43	8.15	10.53
2019	14.07	12.16	8.69	11.22
2020	15.15	13.03	9.21	12.02
2021	15.94	13.62	9.61	12.58
2022	15.98	13.61	9.60	12.57
2023	15.97	13.53	9.58	12.51
2024	15.82	13.33	9.72	12.45
2025	16.40	13.80	9.67	12.70
2026	16.67	14.01	9.80	12.86
2027	16.56	13.89	9.72	12.72
2028	16.38	13.70	9.69	12.57
2029	16.33	13.63	9.62	12.48
2030	16.23	13.52	9.49	12.34
2031	16.11	13.40	9.36	12.18
2032	16.04	13.34	9.32	12.10
2033	16.09	13.39	9.36	12.12
2034	16.19	13.54	9.48	12.22
2035	16.03	13.40	9.40	12.10
2036	15.90	13.31	9.33	11.99
2037	15.70	13.16	9.21	11.83
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1990-1995	-2.80	-2.90	-3.61	-3.08
1995-2000	-0.99	-1.75	-1.63	-1.56
2000-2005	-0.72	0.36	-0.12	0.12
2005-2010	2.22	2.76	3.54	2.97
2010-2015	2.61	1.87	1.68	1.95
2015-2020	5.73	6.04	5.42	5.59
2020-2025	1.61	1.15	0.99	1.10
2025-2030	-0.21	-0.40	-0.39	-0.56
2030-2037	-0.47	-0.39	-0.42	-0.61
2018-2037	0.92	0.74	0.65	0.61

Note: Energy Weighted Average Rates for Indiana IOUs.
Results for the low and high economic activity cases are similar and are not reported.

List of Acronyms

ACGR	Average Compound Growth Rates
Btu	British thermal unit
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DLC	Direct Load Control
DOE	U. S. Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatt-hour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatt-hour
LMSTM	Load Management Strategy Testing Model
LPG	Liquefied Petroleum Gas
MATS	Mercury and Air Toxics Standards
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
NREL	National Renewable Energy Laboratory
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PC	Pulverized Coal-Fired
REMC	Rural Electric Membership Cooperative
REDMS	Residential Energy Modeling System
REEMS	Residential End-Use Energy Modeling System
RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association